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April 23, 2019

VIA HAND DELIVERY

Mr. Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building — First Floor
1300 East Main Street
Richmond, Virginia 23219

RE: Petition of Virginia Electric & Power Company for approval of a rate adjustment clause, designated Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to Virginia Code § 56-585.1 A 5 e

Case No. PUR-2018-00195

Dear Mr. Peck,

Please find enclosed for filing in the above-captioned case an original and one copy of the **Public Version** of the Direct Testimony of Devi Glick on Behalf of the Sierra Club.

If you have any questions or concerns regarding these filings, please do not hesitate to contact me directly.

Thank you,

Evan D. Johns

Evan D. Johns
APPALACHIAN MOUNTAIN ADVOCATES
415 Seventh Street Northeast
Charlottesville, Virginia 22902

Copied: Commission Staff
Service List

COMMONWEALTH OF VIRGINIA
STATE COPRPORATION COMMISSION

In the matter of the Petition of Virginia Electric and Power Company for approval of a rate adjustment clause, designated Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia.

Case No. PUR-2018-00195

Direct Testimony of Devi Glick

On Behalf of Sierra Club

April 23, 2019

PUBLIC VERSION

Summary of the Direct Testimony of Devi Glick

Key Findings:

- In June 2015, the Company would have had knowledge that the economic performance of existing coal plants was in decline due to falling gas and renewable prices, more stringent environmental regulations, and falling load.
- The Company did not have to make all of the capital expenditures in the CHIA project at this time to comply with the state and federal environmental laws and regulations.
- In 2015, the Company had valuable information regarding the current and forward-looking economic status of Chesterfield Units 3 and 4. Both units continued to lose money relative to the PJM markets in almost every year between 2014 and 2018.
- The Company could have reasonably known in 2015 that, with lower market prices and generation levels, net revenues would be higher with a 2019 retirement of the Chesterfield Plant.
- Given substantial planning uncertainty, the Company should have conducted robust economic analysis to compare the cost of the environmental projects and continued operation of the units to alternative options, including retirement and repowering.

Key Conclusions:

- The Company unnecessarily installed wet-to-dry conversion technology at Chesterfield Units 3 and 4 while the plants were actively operating uneconomically.
- The Company should have deferred decisions to install such technology on Chesterfield Units 5 and 6 until plant economics were clear. Deferment should have led to a decision to retire the units in place of the wet-to-dry conversion.
- The decision to construct the landfill was predicated on a need to handle coal ash from continued operation of the Chesterfield coal units; therefore, the landfill itself was unnecessary.

Key Recommendations:

- The wet-to-dry conversion and the landfill and Reymet Road costs associated with the CHIA project are neither reasonable nor prudent.
- The Commission should disallow recovery in Rider E of $124.2 million for the wet-to-dry conversion component of the CHIA project.
- The Commission should disallow recovery in Rider E of $66.8 million for the Fossil Fuel Combustion Product Management Facility and Haul Road and Bridge Project ("landfill") component of the CHIA project.
- The Commission should disallow recovery of any future environmental capital costs tied to ongoing and future operation of the Chesterfield Units 5 and 6.

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1. Introduction and Purpose of Testimony

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Associate with Synapse Energy Economics, Inc.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in electricity and natural gas industry regulation, planning, and analysis. Our work covers a range of issues, including: integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the energy industry.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified before the Virginia State Corporation Commission before?

A No.

Q Please summarize your work experience and educational background.

A I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan; a bachelor's degree in environmental studies from Middlebury College; and more than six years of professional experience as a consultant, researcher, and analyst.

At Synapse, and previously at Rocky Mountain Institute, I focus on a wide range of energy and electricity issues, including: utility resource planning, distributed energy resource valuation, energy efficiency program impact analysis, and economics of plant operations. For this work, I develop in-house models and perform analysis using industry-standard models, including PLEXOS and EnCompass. I have also submitted testimony as part of a docketed proceeding on Public Utility Regulatory Policies Act avoided costs in South Carolina (Dockets 2018-1-E, 2018-2-E, 2018-3-E) and assisted with comments on the same issue in North Carolina.

On topics related to power plant economics, I submitted an expert report for a siting board administrative hearing in the state of Florida (Case No. 18-002124EPP). I have also performed analysis on plant economics in New Mexico,[1] Kentucky (Case No. 2017-00384), Louisiana (Docket 34794), and Nova Scotia[2] for use in reports and colleagues' testimony. On topics related to Coal Ash disposal, I have co-authored comments submitted to the EPA on the March 2018 Regulatory Impact Analysis of EPA's 2018 RCRA Proposed Rule Disposal of Coal Combustion Residuals from Electric Utilities; Amendments to the National Minimum Criteria (Phase One), and I authored an expert report

1 Glick, Devi, et al. Synapse Energy Economics. San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station. Prepared on behalf of Sierra Club. February 25, 2019.

2 Fagan, Bob, et al. Synapse Energy Economics. Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059. Prepared for Board Counsel, Nova Scotia Utility and Review Board. May 1, 2018.

submitted to the North Carolina Department of Environmental Quality on Duke's Energy's coal ash basin closure options analysis.[3]

My CV is attached as Exhibit DG-1.

Q What is the purpose of your testimony?

A The primary purpose of my testimony is to evaluate the historical and projected economic performance of the Chesterfield Units 3, 4, 5, and 6-coal units owned by Virginia Electric and Power Company ("the Company" or "Dominion"). In addition, I evaluate Dominion's capital investments in the environmental projects identified in proposed Rider E to comply with the U.S. Environmental Protection Agency's (EPA) "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Final Rule" (CCR Rule) at the Chesterfield Units, for which Dominion is seeking cost recovery in this docket. Finally, I explore the Company's decision-making regarding environmental investments relative to the Chesterfield plant's economic status, and I discuss the reasonableness and prudency of the Company recovering all operational and capital costs included in Rider E.

Q What documents do you rely upon in your analysis, and for your findings and observations?

A My analysis relies primarily upon the petition, direct testimony, exhibits and schedules, and discovery responses of the Company associated with this proceeding. I also rely to a limited extent on external documents such as EPA Clean Air Markets Division (CAMD) hourly data, Energy Information Administration (EIA) generation and fuel consumption data, and PJM Locational Marginal Pricing data.

Q. Are you sponsoring any exhibits?

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3 Glick, Devi, et al. Synapse Energy Economics. Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina: for Submission to the North Carolina Department of Environmental Quality. Prepared for the Southern Environmental Law Center. February 8, 2019.

A. Yes, I am sponsoring the following exhibits:

Exhibit No.	Contains Confidential or Extraordinarily Sensitive Information?	Contents
DG-1	No	Resume of Devi Glick
DG-2	Extraordinarily Sensitive	Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG 2-11(b) (JJB) – Revised
DG-3	Confidential – only the attachments	Company Response to OAG 4-58, Attachment AG 4-58-3 (TF) CONF
DG-4	No	Company Response to Staff 12-57, Attachment Staff 12-57_BHM
DG-5	No	Company Response to OAG 4-55
DG-6	No	Company Response to OAG 4-57
DG-7	No	Company response to OAG 3-43
DG-8	No	Company Response to OAG 4-60
DG-9	No	Company Response to OAG 7-99
DG-10	No	Company Response to OAG 2-10, Attachment AG 2-10(b) (BMH)
DG-11	Extraordinarily Sensitive	Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG 2-11 (a) (JJB) -Revised
DG-12	Extraordinarily Sensitive	Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG 2-11 (c) (JJB) – Revised
DG-13	Extraordinarily Sensitive	Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG 2-11 (d) (JJB) – Revised
DG-14	Extraordinarily Sensitive	Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG 2-11 (e) (JJB) – Revised
DG-15	Extraordinarily Sensitive	Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG 2-11 (f) (JJB)

		– Revised
DG-16	No	Company Response to OAG 5-69
DG-17	No	Company Response to OAG 6-90
DG-18	No	Company Response to OAG 2-18
DG-19	Confidential	Company Response to OAG 4-58, Attachment AG 4-58-1 (TF) CONF
DG-20	No	Company Responses to OAG 2-15, OAG 2-16, OAG 2-17
DG-21	Extraordinarily Sensitive	Company Response to OAG 7-95, Attachment AG 7-95 (TF) ES
DG-22	No	Company Response to OAG 6-84, Attachment AG 6-84-2 (TF)
DG-23	Confidential	Company Supplemental Response to Sierra Club 2-5, Confidential Attachment Sierra Club 2-05 (k)
DG-24	Confidential	Company Supplemental Response to Sierra Club 2-5, Confidential Attachment Sierra Club 2-05 (l)
DG-25	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (m)
DG-26	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (n)
DG-27	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (o)
DG-28	Extraordinarily Sensitive	Company Supplement Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (h-i) (JF) ES
DG-29	Confidential	Company Response to Staff 8-46, Confidential Attachment Staff 8-46 b (JLM)
DG-30	Extraordinarily Sensitive	Company Supplemental Response to Sierra Club 2-5, Confidential

DG-31	Extraordinarily Sensitive	Company Response to Staff 1-26, ES Attachment Staff Set 1-26 Statement 1 Capital (JCF) R1
DG-32	No	Company Response to OAG 6-80 and OAG 6-81
DG-33	Extraordinarily Sensitive	Company Response to OAG 2-19, Attachment AG 2-19 (TF) ES
DG-34	Extraordinarily Sensitive	Company Response to OAG 6-88, ES Attachment AG 6-88(2)(TF)
DG-35	Extraordinarily Sensitive	Company Response to Sierra Club 3-3, ES Attachment Sierra Club 3-3(b) (TF)
DG-36	Extraordinarily Sensitive	Company Response to Sierra Club 3-3(c)
DG-37	Confidential	Company Response to Sierra Club 2-02(j) (KWD) CONF

2. *Conclusions and Recommendations*

Q Please summarize your findings.

A My primary findings include the following:

1. When the Company made the decision to construct the Chesterfield Integrated Ash Project (CHIA) in June 2015,[4] it would have had knowledge that the economic performance of existing coal plants were in decline due to falling gas[5] and renewable prices, more stringent environmental regulations and falling load.[6]

4 *See* e.g., Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11(b) (JJB) – Revised, attached as Exhibit DG-2.

5 *See, e.g.*, US EIA Annual Energy Outlook, 2014, Figures MT-41 and MT-44 for natural gas price (Henry Hub, $2012) and production data at https://www.eia.gov/outlooks/aeo/pdf/0383(2014).pdf.

6 *See* PJM 2012 Load Forecast Report, Table B-1 and E-1, at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2012-pjm-load-report.ashx?la=en. PJM 2013 Load Forecast Report, Table B-1 and E-1, at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2013-load-forecast-report.ashx?la=en. PJM 2014 Load Forecast Report, Table B-1 and E-1, at https://www.pjm.com/-

2. The Company did not have to make all of the capital expenditures in the CHIA project, at the time they made them, in order to comply with the state and federal environmental laws and regulations. The Company had the option of coming into compliance with the CCR rule through either the installation of the CHIA projects or the retirement or repowering of the Chesterfield units. Such alternatives would have avoided a significant portion of the CHIA investments.

3. Given the substantial planning uncertainty, the Company should have conducted robust economic analysis to compare the cost of the environmental projects and continued operation of the units to alternative options. Such options might include retirement, repowering, or cold storage. The Company did *not* conduct any such robust analysis in the period immediately prior to making the decision to construct. Instead, the Company accelerated its timeline for capital expenditures and construction for the CHIA projects despite uncertainty indicating there might be value to ratepayers in deferring the decision to invest in the CHIA projects.

4. Based on analysis done for the 2015 IRP, and subsequent analysis performed in 2015, the Company had valuable information regarding the economic status of Chesterfield Units 3 and 4. The Company's 2015 economic analysis of Chesterfield Units 3 and 4 concluded that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In addition, data available

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PJM 2014 Load Forecast Report, Table B-1 and E-1, at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2014-load-forecast-report.ashx?la=en. PJM 2015 Load Forecast Report, Table B-1 and E-1, at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2015-load-forecast-report.ashx?la=en.

7 *See* Company Response to OAG Set 4-58, Attachment AG Set 4-58-3 (TF) CONF, attached as Exhibit DG-3.

from the Company and public sources indicates that Chesterfield Units 3 and 4 lost money relative to the PJM energy and capacity markets in almost every year between 2014 and 2018.[8]

5. The Company could have reasonably known, in 2015, that with lower market prices and generation levels, net revenues would be higher if all the Chesterfield units were retired in 2019 and the Company procured equivalent energy and capacity from the market, than if the environmental projects were carried out and the Chesterfield units continue to operate. I found this result by conducting an economic retirement analysis that approximated the analysis the Company could have done in 2015. My analysis encompassed (1) all four of the Chesterfield coal-fired units as a whole, and (2) Chesterfield Units 3 and 4 separately. This analysis, covering unit operation in the 2015-2023 time period, assumes the Company's projection of future generation levels, as well as PJM energy and capacity market prices as used in its 2015 IRP analysis. I then conducted the same analysis assuming actual generation levels, and PJM energy and capacity market prices for the 2015-2018 period, with a projection for 2019-2023.

6. The Company's forecasts of future generation from the Chesterfield units, at the time the CHIA project was planned and executed, indicates that the Company over-sized and over-built the new $67 million landfill component of the CHIA project based on an expectation that the coal units would operate economically and at unrealistically high capacity factors into the future. The Company (1) failed to defer the decision to construct the landfill until there was greater market and regulatory certainty; and (2) failed to conduct robust economic analysis that would have indicated that the plants were not going to economically operate at historical levels, and thus there would be significantly lower levels of coal ash requiring disposal, if any at all.

8 Calculations based on Synapse analysis. *See* Section 5.

Q Please summarize your conclusions.

A I conclude as follows:

- The Company developed and executed plans to unnecessarily install wet-to-dry conversion technology at Chesterfield Units 3 and 4 while the plants were actively operating uneconomically.
- The Company failed to defer decisions on installing such technology on Chesterfield Units 5 and 6 when faced with uncertainty about whether or not operation of Chesterfield Unit 5 and 6 would be economic over the near and long-term. A reasonable decision to defer installation on Chesterfield Units 5 and 6 should have led to a decision to retire the units, given the market information revealed during the 2016-2018 period, thereby making the installation of wet-to-dry conversion technology on Chesterfield Units 5 and 6 also unnecessary.
- Since the decision to construct the landfill was predicated on a need to handle coal ash associated with continuing—though uneconomic—operation of the Chesterfield coal units, the landfill itself was unnecessary. Coal ash from existing operations through 2020 could have been handled in the existing ash pond structures.
- As such, (1) the wet-to-dry conversion, and (2) the landfill and Reymet Road costs associated with the CHIA project are neither reasonable nor prudent.

Q Please summarize your recommendations.

A My recommendations are as follows:

1. The Commission should disallow recovery in Rider E of $124.2 million for the wet-to-dry Conversion component of the CHIA project. Of this total, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

2. The Commission should disallow recovery in Rider E of $66.8 million for the Fossil Fuel Combustion Product Management Facility and Haul Road and Bridge Project ("landfill") component of the CHIA project.
3. The Commission should disallow recovery of any future environmental capital costs tied to ongoing and future operation of the Chesterfield Units 5 and 6.

3. *Summary of the Environmental Projects Covered Under the Proposed Rider E*

Q Please provide a summary of the proposed Rider E.

A Proposed Rider E consists of three categories of costs (1) asset retirement obligation (ARO) expenses associated with existing assets that must be closed; (2) newly constructed assets and associated expenses; and (3) ARO expenses associated with newly constructed assets. These cost cover environmental projects at the Chesterfield Power Station, Clover Power Station, and the Mount Storm Power Station.[9]

Q Do you take a position on the costs incurred under the proposed Rider E at the Clover or Mount Storm Power Stations?

A No. I am not providing testimony on the costs incurred under the proposed Rider E at Clover or Mount Storm, nor do I take a position on those costs.

Q Do you take a position on the ARO expenses?

A No. I am not providing testimony on the ARO costs—only the new capital costs.

Q What is the CHIA Project?

A The CHIA project consists of three components:

1. A wet-to-dry conversion for Chesterfield Units 3, 4, 5 and 6 to dry fly ash handling and closed loop bottom ash/pyrite handing ("wet-to-dry

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9 *See* Direct Testimony of Cathy Taylor at 1-2.

system"). The estimated construction cost for this component is $124.2 million.

2. Construction of a new a Fossil Fuel Combustion Products (FFCP) Management Facility ("landfill"). The estimated construction cost for this component is $66.8 million.
3. Construction of a new Low Volume Wastewater Treatment System ("LVWWTS"). The estimated construction cost for this component is $55.9 million.

These capital projects (together the "CHIA project" or the "environmental projects") are estimated to cost a total of $246.8 million.[10]

Q Why did the Company undertake the CHIA project?

A The Company says that it undertook the environmental projects in order to maintain compliance with the following state and federal environmental regulations:

1. U.S. Environmental Protection Agency's ("EPA") "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Final Rule," 80 Fed. Reg. 20,301 (April 17, 2015) (codified at 40 CFR Parts 257 and 261) (the "CCR Rule"), which is incorporated into the Virginia Solid Waste Management Regulations, 9 VAC 20-81-800 to 820;[11] and
2. The EPA's Steam Power Generating Effluent Guidelines (40 CFR Part 423) ("Effluent Guidelines" or "ELG"), which are incorporated into Virginia state law under 9 VAC 25-31-30.[12]

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10 *See* Direct Testimony of Cathy Taylor at 3-4.

11 *See id.*

12 *See* Direct Testimony of Cathy Taylor at 4.

Collectively the CCR and ELG rules are referred to as the "environmental laws and regulations," which allowed the Company to continue to operate and serve its native load.[13]

Q **When did the CCR and ELG rules take effect?**

A The timeline for the proposed and final CCR and ELG rules is summarized in Table 1 below. The CCR rule was proposed in June 2010, and the ELG rule was proposed in June 2013. The final CCR rule went into effect in April 2015 and the final ELG rule went into effect in November 2015.

Table 1: Timeline of CCR and ELG regulations

Environmental Law	**CCR**	**ELG**
Proposed Rule	June 2010	June 2013
Final Rule	April 2015	November 2015
Compliance Date (according to Dominion)	November 2018	November 2018
Compliance Date (Synapse assessment)	October 2020	October 2020

Source: Attachment Staff Set 12-57_BHM

Q **What was the deadline for the Company to comply with the CCR and ELG rules at Chesterfield as asserted by the Company?**

A. According to the Company, and as illustrated in Table 1, the deadline was November 2018.[14] However, my understanding is that this compliance date was triggered by the Company's application for a new permit from the Virginia Pollutant Discharge Elimination System (VPDES) in September 2016.

13 *See* Direct Testimony of Cathy Taylor at 10.

14 *See* Company Response to Staff Set 12-57, Attachment Staff Set 12-57_BHM, attached as Exhibit DG-4, *see* also Company Response to OAG Set 4-55, attached as Exhibit DG-5.

Q Did the Company have any other alternatives with respect to the compliance date of the VPDES permit?

A Yes. It is my understanding that the Company did not have to apply for reissuance of its VPDES permit in September 2016 and seek the earliest possible compliance date of November 2018. The Company could have had up to five additional years (November 2023) to seek reissuance of its VPDES permit and comply with the ELG regulations,[15] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Q Why did the Company choose to pursue the permit in 2016 rather than defer?

A I am not clear on why the Company rushed ahead with the VPDES permit at Chesterfield and with accelerating the dates of implementation of the CHIA project from **[BEGIN CONFIDENTIAL]** [redacted][18] **[END CONFIDENTIAL]**. When asked about this the Company indicated that the schedule was adjusted "based on the need to meet environmental compliance deadlines associated with CCR regulations and coordination with planned station

15 *See* Federal Register / Vol 80, No 212. November 3, 2015. "Consistent with the proposal and supported by many commenters, the final rule takes this approach in order to provide the time that many facilities need to raise capital, plan and design systems, procure equipment, and construct and then test systems. It also allows for consideration of plant changes being made in response to other Agency rules affecting the steam electric industry (see Section V.B.)"..."For purposes of the BAT limitations in this rule, this preamble uses the term ''legacy wastewater'' to refer to FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, or gasification wastewater generated prior to the date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023 (see Section VIII.C.7)."

16 *See* Exhibit DG-2, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11(b) (JJB) – Revised.

17 *See* Company Response to Sierra Club Set 2-2, Attachment Sierra Club Set 2-20(j) (KWD) CONF, attached as Exhibit DG-37.

18 *See* Exhibit DG-2, *see also* Company Response to OAG Set 4-57, attached as Exhibit DG-6.

outage in Fall 2017, as understood at the point in time that such presentation were presented."[18]

The result of accelerating compliance and implementation is that in doing so, the Company reduced its ability to pursue alternatives ways to comply (including retirement), and foreclosed on the opportunity to gain a better understanding of the economics of the Chesterfield Units prior to beginning the CHIA project.

I will note that the Company was asked about compliance flexibility and consideration of alternatives in multiple discovery requests. It failed to provide a clear answer on the latest possible date that the Company could have legally deferred compliance and why this decision was rushed.

Q **Did any factors besides the VPDES permit limit the compliance timeline?**

A Yes. It is my understanding that lower and upper ash ponds triggered compliance with the CCR regulation based on (1) exceedance of groundwater protection standards and (2) failure to meet location restrictions for placement of CCR.[19] The Company states that this triggered a deadline for commencing closure on or about October 2018. However, the CCR regulations state that the deadline is "within six months of making such determination *or* no later than October 31, 2020, whichever date is later."[20]

Q **What was the deadline for the Company to comply with the CCR and ELG rules at Chesterfield based on the factors outlined above?**

A Evaluating the timeline for these two regulations together, it is my understanding that October 31, 2020 was the final compliance date. This is supported by a Company discovery response which stated that ELG regulations that were

18 *See* Exhibit DG-6.

19 *See* Company Response to OAG 4-60, attached as Exhibit DG-8.

20 *See* 40 CFR § 257.101- Closure or retrofit of CCR units, available at https://www.govinfo.gov/content/pkg/FR-2018-07-30/pdf/2018-16262.pdf.

incorporated into the station's VPDES permit required flyash and bottom ash sluicing to the Lower Ash Pond to cease by October 2020.[21]

Table 2: Timeline of environmental project construction

	Landfill	Wet-to-Dry Conversion	Low Volume Waste Water Treatment
Contract Date	January 2016 (road: May 2015)	June 2015	August 2016
Project Completion	September 2017	December 2017	October 2017

Source: Exhibit DG-4, Company Response to Staff 12-57, Attachment Staff Set 12-57_BHM; Company Response to OAG 3-43, attached as Exhibit DG-7.

Q Have you identified a specific date when the Company made the decision to proceed with the CHIA project?

A Yes, it was June 2015, **[BEGIN CONFIDENTIAL]** [redacted][22] **[END CONFIDENTIAL]**.

Q Was the CHIA project required in its entirety in order to comply with the CCR and ELG rules?

A No. The Company could have pursued alternatives such as retirement of the Chesterfield coal units. The entire CHIA project was not required on the timeline or scale on which the Company proceeded. The wet-to-dry conversion and the landfill were avoidable in part if Units 3 and 4 were retired, and avoidable in whole if Units 3—6 retired prior to the compliance deadline. These costs were incurred to allow Chesterfield Units 3—6 to continue to operate beyond the date at which their future operations would cease to be of economic benefit to the ratepayers.

21 *See* Company Response to OAG 7-99, attached as Exhibit DG-9.

22 *See* Exhibit DG-2, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11(b) (JJB) – Revised.

Q **Did the Company identify a reason for the CHIA project other than environmental compliance?**

Yes. The Company identified the need for a new coal ash storage facility in a 2009 report on Alternative Site Analysis. This report stated that current Fossil Fuel Combustion Products (FCCP) storage facility at Chesterfield was anticipated to reach its design capacity around 2019.[23] Therefore a new facility would be needed in 2019 to allow continued operation of the Chesterfield power station.

4. *Summary Background on regional and PJM Market Conditions and Implications for Existing Coal Units at the Time of the CHIA Decision (2014-2015)*

Q **Was there sufficient evidence at the time of the first CHIA investment decision in June 2015, that the Chesterfield units were likely to be economically impaired in the near future, or within their foreseeable lifetimes?**

A Yes. There were a number of clearly emerging trends all of which would have had an effect on estimates made by June 2015 of economic loss from Chesterfield coal plant operations during ensuring years. These trends include: falling gas prices, the emergence of long-delayed regulations that sought to internalize the costs of coal pollution under the Obama administration, stagnant load growth, and the rapid emergence of cost-effective renewable energy. All of these factors would have contributed to a less attractive operating environment for coal leading up to a June 2015 assessment. In fact, as early as 2010, the North American Reliability Council had estimated that more than 5,000 MW of coal generation was at risk of being non-economic in Virginia and the Carolinas, [24]

23 *See* Company Response to OAG Set 2-10, Attachment AG Set 2-10(b) (BMH), attached as Exhibit DG-10.

24 NERC Special Reliability Assessment, October 2010, available at http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

and in 2011, the utility trade group Edison Electric Institute projected the retirement of up to 38 GW of coal in the southwestern United States by 2020 with the combination of environmental regulations and moderate gas prices.[25]

Q Please summarize background conditions regarding natural gas production and pricing, and the impact these conditions had on PJM market prices.

A The rapid development and deployment of hydraulic fracturing, allowing for the extraction of oil and natural gas from shale in the mid-200s led to gas prices – and more importantly, gas projections – falling from 2005 and 2014[26] and elsewhere. Natural gas-fueled combined cycle plants in PJM are a key competitor to coal-fired generation. The development of shale gas ushered in the beginning of a trend[27] towards greater displacement of coal-based energy with natural gas-fueled generation.

PJM energy market prices began to see the effect of increasing amounts of natural gas generation on the margin, among other factors, leading to downward price pressures.[28]

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25 Edison Electric Institute, Potential Impacts of Environmental Regulations on the U.S. Generation fleet. January 2011, available at https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf

26 *See, e.g.*, US EIA Annual Energy Outlook, 2014, Figures MT-41 and MT-44 for natural gas price (Henry Hub, $2012) and production data at https://www.eia.gov/outlooks/aeo/pdf/0383(2014).pdf.

27 *See, e.g.*, US EIA Annual Energy Outlook, 2018, Slides 83, 87, and 89 for changing fuel shares (increasing gas, decreasing coal) at https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.

28 *See e.g.*, broad price trends in PJM, 2018 State of the Market Report, Figure 3-56, Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through December 2018. Volume 2, page 190. This figure illustrates downward price trends in PJM between 2008 and 2014 (and continuing into present day), with spikes seen for "polar vortex" months. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf

Q Please summarize background conditions regarding government regulations and how these conditions impacted utility planning for coal-fired generators.

A The Company was conducting resource planning in an environment where coal-fired power plants faced federal regulations pertaining to coal ash, plant effluents, carbon emissions, hazardous pollutants (mercury and other toxic emissions), air quality standards, and Clean Water Act issues. In combination, these regulations effectively imposed or threatened to impose increased relative costs on coal-fired generation compared to alternative sources (renewable energy, energy efficiency, and gas-fired generation).

Q Please summarize background conditions regarding load and demand in PJM.

A The load forecast (for summer peak, and for annual net energy) in PJM for a given future year was declining with each passing forecast vintage, and market participants were aware of this fact because the reports are public. For example, in 2012 PJM forecasted an RTO zone peak load for the year 2017 of 167,433 MW (prior to reductions for energy efficiency and load management) and an annual net energy requirement of 895,748 GWh. Just two years later, PJM's 2014 Load Forecast for the year 2017 projected a summer peak of 164,195 MW (more than 3,000 MW lower than the earlier forecast for the same year, or 1.9 percent lower) and an annual net energy demand of 870,847 GWh (2.7 percent lower than the earlier year forecast for the same year).[29] This pattern is important because it indicates that future year supply and demand balances, as considered in resource planning exercises, need to account for the presence of exaggerated load-side forecasts, which indicates that in the real world prices will be lower because demand is lower. The actual PJM peak load in 2017 (after including

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29 *See* PJM 2012 Load Forecast Report, Table B-1 and E-1, at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2012-pjm-load-report.ashx?la=en. PJM 2014 Load Forecast Report, Table B-1 and E-1, at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2014-load-forecast-report.ashx?la=en.

distributed solar resources not reflected in the earlier forecasts) was 145,331 MW and the actual annual net energy was 772,291GWh.[30]

Q **Please summarize background conditions regarding renewable resources as resource alternatives to coal-fired generation.**

A In 2014, projections for increased penetration of renewable resources were higher for those scenarios examining the effects of greenhouse gas reduction policies,[31] reflecting better overall economics for wind and solar technologies. The Company was examining resource planning issues while directly considering greenhouse gas reduction policies.[32] At that point in time, technological progress, declining costs, and very low purchase price arrangements for wind power were in existence,[33] even though the status of

30 *See* PJM 2018 Load Forecast Report, Table B-1. https://www.pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx?la=en. PJM 2019 Load Forecast Report, Table F-2. https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en.

31 *See*, for example, the discussion on renewable electricity penetration in markets, in the 2014 Annual Energy Outlook, Issues in Focus section, pages IF-41 to IF-44, and especially Figure IF7-2, for the "GHG25" case, projecting steep then-near-term increases in renewable electricity penetration. https://www.eia.gov/outlooks/aeo/pdf/0383(2014).pdf.

32 *See* Dominion 2014 IRP, Filling letter to Joel H. Peck, Clerk, Virginia State Corporation Commission State Corporation Commission, August 29, 2014, pages 1-2 include the following: "To develop the 2014 Plan, the Company evaluated a wide range of options for meeting customer demand in a highly uncertain energy policy and regulatory environment, most recently influenced by the June 2014 issuance of the U.S. Environmental Protection Agency's ("EPA") draft Rule 111 (d), or "Clean Power Plan," that would require a significant reduction in carbon emissions from existing sources of power generation and impose binding carbon intensity targets on each state's electric generation fleet." … "Given the Clean Power Plan's tight timelines for compliance and the complexities and potential effect on our customers, the Company believes it is prudent to begin planning now for implementation of a final rule that is substantially similar to the proposed rule. …"

33 *See* the US DOE/Lawrence Berkeley National Laboratory "2013 Wind Technologies Market Report", August 2014. https://www.energy.gov/sites/prod/files/2014/08/f18/2013%20Wind%20Technologies%20Market%20Report_1.pdf

Federal tax policies for wind was at that time (August 2014) uncertain. Solar technologies were continuing to improve, and costs for solar resources were declining rapidly at that time.[34]

Q Please summarize background conditions in PJM and the region in respect to projections for economic operation of existing coal plants in 2015.

A The above background points illustrate that the Company should have been exhaustively examining various retirement scenario options, coupled with increased energy from alternative resources, to minimize potential negative ratepayer impacts associated with relying too greatly on coal-fired resources for future energy. The Company should have been aware of the effect that the elements described above would exert on forward energy clearing prices and capacity clearing prices, and their effect of placing upward pressure on the costs to operate regulation-compliant coal plants.

5. The Company relied on limited economic analysis to plan and execute the CHIA project and did not adequately consider alternatives

Q When did the Company decide to implement the CHIA Project?

A As stated above, the Company began planning portions of the CHIA Project as far back as 2009, before the CCR and ELG rules were both proposed.

The Company conducted an analysis regarding the environmental projects in 2011 when the Mercury and Air Toxic Standards (MATS) and Clean Water Act 316 (b) rules were proposed.[35] **[BEGIN CONFIDENTIAL]** [redacted]

34 *See* the US DOE/Lawrence Berkeley National Laboratory "Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013", September 2014. http://eta-publications.lbl.gov/sites/default/files/lbnl-6858e.pdf

35 *See* Exhibit DG-3, Company Response, to OAG Set 4-58.

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[redacted][36] [END CONFIDENTIAL]

Q How did the Company justify its decision to pursue the CHIA Project at the scale and timeline outlined?

Despite evidence to the contrary—detailed in subsequent sections of my testimony—the Company claims that the Chesterfield Plant was operating economically prior to the execution of the CHIA Project in 2015. Therefore, the Company claims, it had no reason to believe the plants would not continue to economically serve native load obligations for the foreseeable future.[37]

Q What is the basis for the Company's claim that Chesterfield Units 3—6 were operating economically?

In 2011, the Company evaluated the impact of anticipated future environmental regulations on the economics of operating many of its old units that would require retrofits.[38] The Company stated that this analysis was integrated into its 2011 IRP.[39]

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36 *See* Company Response, to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (a) (JJB) - Revised, attached as Exhibit DG-11. *See* Exhibit DG-2, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (b) (JJB) - Revised. *See* Company Response, to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (c) (JJB) - Revised, attached as Exhibit DG-12. *See* Company Response, to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (d) (JJB) - Revised, attached as Exhibit DG-13. *See* Company Response, to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (e) (JJB) - Revised, attached as Exhibit DG-14. *See* Company Response, to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (f) (JJB) - Revised, attached as Exhibit DG-15

37 *See* Company Response, to OAG Set No 5-69, attached as Exhibit DG-16. *See* Company Response to OAG 6-90, attached as Exhibit DG-17.

38 *See* Exhibit DG-3, Company Response to OAG Set 4-58.

39 *See* Company Response to OAG Set 2-18, attached as Exhibit DG-18.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Based on this analysis, the Company found that:

[BEGIN CONFIDENTIAL]

[redacted]

40 *See* Company Response to OAG Set 4-58, Attachment AG Set 4-58-1 (TF) CONF, attached as Exhibit DG-19.

[redacted][41] [END CONFIDENTIAL]

Q Do you agree with the methodology, results and recommendations of the 2011 analysis as laid out by the Company?

A The framework and approach are reasonable. However, I did not review or assess the inputs and results because the analysis was too old to have been be reasonably relied upon when making economic operations and retirement decisions in 2015.

Q Given the large number of potential environmental regulations that the Company was facing in the upcoming years, and the significant cost of the capital projects, did the Company repeat the 2011 analysis in 2015 to evaluate retirement or re-firing, prior to beginning the CHIA Project in 2015?

A No. The Company states that "IRPs subsequent to the 2011 IRP have continued to assess and evaluate the financial and other impacts of such rules, including after those rules were finalized."[42] However, Dominion provided no additional analysis demonstrating any form of robust evaluation of future Chesterfield plant operations up to and beyond the purported CCR/ELG compliance deadlines in 2018.

Dominion instead repeats its claim that "at the time the decisions were made to implement those projects in order to ensure compliance with environmental law and regulations, the coal units at the Power Stations economically were serving the Company's native load."[43]

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41 *See* Exhibit DG-19 Attachment AG Set 4-58-1 (TF) CONF.

42 *See* Exhibit DG-18, Company Response to OAG Set 2-18.

43 *See* Company Response to OAG Set 2-15, OAG Set 2-16, and OAG 2-17, attached as Exhibit DG-20.

Q Did Dominion consider placing the Chesterfield units into "cold storage", or similarly reducing overall operation, and therefore coal ash production, until there was greater certainty around environmental compliance and the regulatory environment?

A No. Dominion claims that "from the time these rules were proposed in 2011, and until they became effective in 2015, the Chesterfield Plant was economically serving native load and was forecasted to do so for the foreseeable future. Retirement and cold storage were not considered given the high utilization of the Chesterfield Plant."[44]

Q What economic analysis did the Company perform between 2012 and 2015 that would support its assertion that the plants were operating economically through 2015, when the CHIA Project began?

A [BEGIN CONFIDENTIAL] [redacted]

[redacted]

44 *See* Exhibit DG-16, Company Response to OAG Set 5-69.

45 *See* Company Response to OAG Set 7-95, Attachment AG Set 7-95 (TF) ES, attached as Exhibit DG-21.

46 At Risk units include Chesterfield 3-6, Mecklenburg 1-2, Possum Point 5, Yorktown 3.

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

Additionally, since the Company claims that it evaluated the environmental projects as part of every IRP since 2011, it also would have evaluated the projects in the 2015 IRP, which was published in July 2015.

This 2015 analysis is important because the CHIA Project capital costs at issue in Rider E were incurred between 2015 and the present. If Dominion knew, or should have reasonably known, that any of the Chesterfield units were operating uneconomically, or were likely to become uneconomic, then the Company should have at least initially delayed the decision to incur capital expenses of the scale incurred.

Q Why is the 2015 IRP important in this case?

A The Company did not provide any information on the input assumptions that it used in Strategist to model the retirement scenarios discussed above. However, based on the timeline of these results, it is likely that the analysis relied on the 2015 IRP inputs relating to generation, capital costs, and commodity prices. The IRP inputs are available to analyze and evaluate.

Q Do you agree with the Company's economic analysis in the 2015 IRP of the Chesterfield units?

A No, the Company relied upon a flawed and incomplete analysis that failed to robustly test sensitivities around future plant operations and power market costs. Testing for these sensitivities would demonstrate that the Chesterfield units would continue to operate economically and that retirement scenarios had a lower NPV than continued operations and investment in the environmental projects.[47]

Specifically, Dominion relied on (1) ICF Commodity Price Forecasts from Spring 2015, which projected exceptionally high power and capacity market prices between 2015 and 2030; and (2) high capacity factor assumptions for each of the Chesterfield units which deviated from recent operational realities.[48] These two factors together produced results that showed unreasonably high net revenues from continued operation of the Chesterfield units.

There is no evidence that the Company conducted robust sensitivity analysis around plant operations and power market prices to understand how the retirement results would be impacted by changes in these crucial inputs. It is

47 *See* Exhibit DG-21, Attachment AG Set 7-95 (TF) ES. *See also* Exhibit DG-3, Attachment AG Set 4-58-3 (TF) CONF.

48 *See* Dominion 2015 IRP, July 1, 2015, Appendix 4A and Appendix 3D.Case No. PUE-2015-00035, available at http://www.scc.virginia.gov/docketsearch#caseDocs/134454.

extremely disconcerting that the Company entered into contracts for $246.8 million in capital project without performing this analysis.

Q **Can you estimate what the Company would have found if it had conducted sensitivity analysis in 2015?**

Yes. The Company would have found that if it tested sensitives around lower PJM power prices, lower PJM capacity prices, and lower generation levels, retirement of some of all of the units resulted in a significant increase in net revenue (relative to the market)[49] compared to the baseline of completing the environmental projects and continuing to operate the units.

I found this by conducting a retirement analysis based on the 2015 IRP inputs. For each year between 2015 and 2023,[50] I calculated the annual net revenue for each unit relative to the market. I then tested power price and generation sensitivities (1) without any Chesterfield retirement; (2) with the retirement of Units 3 and 4; and (3) with the retirement of all four Chesterfield units.

Table 4 shows the retirement analysis using all of the Company's inputs and assumptions from its 2015 IRP. These results approximate what the Company would have found if the Company performed its own retirement analysis in 2015 with its baseline IRP assumptions. In this scenario, the Company see a lower net revenue relative to the market in both retirement scenarios. This scenario relies on unrealistically high-power prices and generation assumptions—which deviate significantly from what actually happened—to produce the net revenue results.

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49 Net revenue is the market value of energy and capacity, and ancillary services when available, less the costs of operation inclusive of capital additions required to meet regulations.

50 The Company did not model a long-term preferred portfolio in its 2015 IRP due to uncertainty around the CPP, and therefore did not provide generation assumptions beyond 2023.

Table 4: Net revenue 2015-2023 relative to the market for retirement sensitivities – 2015 IRP baseline capacity factors and power prices

	No Retirements	Retire Units 3 and 4	Retire all Chesterfield units
Unit 3	$19.16	$17.73	$17.73
Unit 4	$118.52	$48.31	$48.31
Unit 5	$313.68	$313.68	$110.75
Unit 6	$565.71	$565.71	$205.60
Total Net Revenues	$1,017.06	$945.43	$382.40
Net Revenue relative to no retirements*		-$71.64	-$634.66

*Source: Synapse calculations. *Positive value indicates savings.*

Table 5 shows a retirement analysis using lower PJM power prices, lower PJM capacity prices, and decreased generation levels. If the Company had tested sensitives around lower generation levels and lower power and capacity prices, it would have seen that the net revenue relative to the market would be lower if it continued to operate the Chesterfield plant than if it retired some or all of the units.

Specifically, I calculated net revenues relative to the market to result in a loss of over $311 million with no retirements modeled. When Chesterfield Units 3 and 4 are retired, and the equivalent energy and capacity is procured from the market, losses drop to only 283.7 million. This is an increase in revenue of $27.7 million, When all Chesterfield units are retired, and the equivalent energy and capacity is procured from the markets, losses drop even more to $198.4 million relative to the market. This is an increase in revenue of $113 million.

Table 5: Net revenue 2015-2023 relative to the market for retirement sensitivities – actual capacity factors and actual and 2018 IRP PJM power and capacity prices

	No Retirements	Retire Units 3 and 4	Retire all Chesterfield units
Unit 3	$(32.7)	$(8.1)	$(8.1)
Unit 4	$(23.8)	$(20.7)	$(20.7)
Unit 5	$(21.6)	$(21.6)	$(100.7)
Unit 6	$(233.3)	$(233.3)	$(68.9)
Total Net Revenues	$(311.4)	$(283.7)	$(198.4)
Net Revenue relative to no retirements*		$(27.7)	$(113.0)

Source: Synapse calculations.

Q How did you select the PJM power prices, PJM capacity prices, and capacity factors sensitivities and why are they appropriate to test?

I designed the sensitivities to answers the question, "if the Company had modeled power prices, capacity prices, and generation sensitivities that approximated what actually happened over the past three years, combined with what the Company is currently projecting will happen in the near future, what would it have found in the way of economic retirement?"

I modeled generation levels based on actual generation levels from the past three years, continuing to 2023 with a gradually declining capacity factor.[51] I modeled power prices based on actual PJM DOM hub prices over the past three years, combined with ICF's 2018 power price forecast going forward. I modeled capacity prices based on ICF's 2015 capacity price forecast for the first three years, and then PJM's 2018 capacity price forecast going forward.

The magnitude of the sensitivities are appropriate and reasonable because (1) there was significant uncertainty around future plant operation, based in large part on the Clean Power Plan, and it was likely that old, high emission units such as Chesterfield would need to have to significantly ramp down generation levels; (2) the price of natural gas and renewables were both dropping, which was likely to lead to lower power market prices in the near future; and (3) the sensitivities represent what actually happened.

Q How did you calculate net revenues relative to the market in Table 5?

I calculated energy revenues relative to the market based on planned generation levels provided by the Company from a September 2014 Promod run,[52] and the No CO_2 Case power prices from the ICF Commodity Price Forecast for Spring

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51 No change for Unit 3, 0.5% decline for Unit 4, and 1% decline for Units 5 and 6.

52 *See* Company Response to OAG 6-84, Attachment AG Set 6-84-2 (TF), attached as Exhibit DG-22.

2015 (with forward market prices used for the first 18 months). I calculated capacity revenue based on the ICF capacity prices from the No CO_2 Case.

I used O&M and capital costs provided by the Company from a September 2014 Promod run.[53] I separated out fixed and variable O&M and re-allocated the variable costs on a $/MWh basis and not a total dollar basis. I calculated fuel costs based on the fuel costs provided in the 2015 IRP and the Unit's average heat rates.

I then calculated net revenue relative to the market of Units 3-6 between 2015 and 2023. To test the retirement scenarios, I removed all capital costs incurred between 2015 and 2018,[54] and then retired the units in 2019. I added the cost of procuring energy and capacity equivalent to what was retired from the PJM market from 2019—2013.

To test the generation sensitivities, I recalculated energy revenues, variable costs, and fuel costs based on updated generation assumptions. To test power price sensitivities, I recalculated energy revenues based on actual power prices through 2018, and then 2018 ICF power price projections through 2023. To test capacity price sensitivities, I recalculated capacity revenues based on ICF's capacity price projections for 2015 through 2017, and then used 2018 ICF power price projections through 2023.

53 *See id.*

54 A conservative assumption that if the Company decides in 2015 to retire the Plant in 2029, it will stop investing in all sustaining capital costs and capital upgrades for the units.

Q Based on the above analysis, what should the Company have known in June 2015 when it signed the contract for the wet-to-dry component of the CHIA project?

A The Company knew how much future regulatory and market uncertainty it was facing. The Company discusses this explicitly in the 2015 IRP, published July 1, 2015 stating:

> "Because of this period of uncertainty, the Company's 2015 Plan include no long-term recommendations beyond the Short-Term Action Plan...The Company maintains that the proposed Clean Power Plan requires Dominion, its regulators, and other stakeholders to pause and fully reevaluate the Company's strategic path forward once the Clean Power Plan is made final."[55]

Despite this public acknowledgement of uncertainty, the Company signed a contract for the $124 million wet-to-dry project one month prior, in June 2015, proceeding with long-term plans to maintain its coal plants.

Given this level of uncertainty, the Company should have exhaustively assessed the sensitivity of the Company's near-term findings from May 2015,[56] and the retirement decision in its 2015 IRP. The Company should have realized the value in deferring capital investments until there was greater future certainty around the future economics of operating the Chesterfield units.

Furthermore, Dominion knew that Chesterfield Units 3, 4, and 5 were **[BEGIN CONFIDENTIAL]** [redacted]

55 *See* Dominion 2015 IRP, July 1, 2015, page 5. Case No. PUE-2015-00035, available at http://www.scc.virginia.gov/docketsearch#caseDocs/134454.

56 *See* Exhibit DG-21, Attachment AG Set 7-95 (TF) (ES).

57 In January 2014, PJM experienced a "polar vortex." During the polar vortex, peak demand was 25% higher than usual, and the forced outage rate was two to three

[redacted]

[END CONFIDENTIAL]

Q Please summarize your findings regarding the economic performance of Chesterfield Units 3- 6 between 2013 and 2018.

A **[BEGIN CONFIDENTIAL]** [redacted]

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times normal levels. A few weeks later, the PJM area was hit with another few weeks of extreme cold temperatures and winter storms. During these cold snaps, energy prices spiked to extreme levels, reaching a max of $923/MWh and averaging $122/MWh for the month of January. This spike in energy prices resulted in high energy revenues in 2014 (which can be seen in [redacted]).

[redacted] **[END CONFIDENTIAL]**

Q Describe how you arrived at the net revenue results in Confidential Table 6.

A The net revenue values in Confidential Table 6 are based on the Company's data related to each plant's energy revenues, ancillary revenues, capacity revenues, fuel costs, O&M costs, and capital costs. The Company provided historical annual energy revenues, ancillary revenues and capacity revenues for Chesterfield Units 3-6.[58]

The Company did not provide historical fuel costs for each of the Chesterfield units. To calculate each unit's fuel costs, I used historical fuel consumption and fuel receipts data from the EIA.[59]

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58 *See* Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (k), attached as Exhibit DG-23. *See* Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (l), attached as Exhibit DG-24. *See* Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (m), attached as Exhibit DG-25. *See* Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (n), attached as Exhibit DG-26. *See* Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (o),attached as Exhibit DG-27.

59 *See* EIA form 923, p.3 Boiler Fuel Data, and p.5 Fuel Receipts, available at https://www.eia.gov/electricity/data/eia923/.

The Company directly provided annual historic variable and fixed O&M expenses by plant associated with power generation at the Chesterfield plant.[60] Since costs were at the plant level, I converted variable O&M costs into $/MWh based on annual historical plant operations, and then I allocated variable O&M costs to each unit based on actual historical generation data.[61] I converted the fixed O&M costs into $/kW-year based on total plant nameplate capacity and then allocated them across each unit.

The Company directly provided annual historic spending on system capital additions for the Chesterfield plant.[62] Since the costs were at the plant level, I converted into $/MW-year based on total plant nameplate capacity, and then allocated them across each unit.

Finally, I subtracted fuel, O&M, and capital cost from each plant's energy, ancillary, and capacity revenues to arrive at annual net revenues.

Q **Does this analysis include all of the Company's costs associated with operating Chesterfield Units 3—6 between 2013 and 2018?**

A No. The Company also incurred $189 million in capital costs for the wet-to-dry conversion and the landfill components of the CHIA Project.[63] The Company also reported incremental O&M costs. These costs were incurred to keep the plant operational and therefore should be included in the net revenue

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60 *See* Company Supplement Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (h-i) (JF) ES, attached as Exhibit DG-28. **[BEGIN ES/CONFIDENTIAL]** [redacted] **[END ES/CONFIDENTIAL].**

61 *See* Company Response to Staff Set 8-46, Confidential Attachment Staff Set 8-46 b (JLM), attached as Exhibit DG-29.

62 *See* Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (j) (JF) (ES), attached as Exhibit DG-30.

63 *See* Direct Testimony of Mark Mitchell at 2.

calculations. It does not appear that these costs were included in the historical capital cost and operational cost values reported by the Company.[64]

Q What impact would these costs have on the net revenue of the Chesterfield units from 2013—2018?

A The total estimated cost for the wet-to-dry conversion and the landfill components of the CHIA projects of $189 million spread over the four units during the years the cost were incurred (2015 – 2018) equates to an "adder" to regular operational costs of:

- $35/kW-year on a capacity basis; or
- $10/MWh over the 18,391 GWh of generation from the four units.

Q How did you arrive at these net revenues?

CHIA Project capital costs were provided at a plant level in Schedule 46 A.[65] I used the same approach to allocate the costs across units based on nameplate capacity as I did with the power generation capital costs. I also allocated incremental O&M costs associated with the CCR and environmental upgrades across units based on nameplate capacity.[66]

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64 The Company reported a total of just over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in capital expenditures for Units 3-6 over the years 2015 – 2018 (removing expenditures on units 7&8 as reported in FERC form 1 from total capital expenditures provided by Dominion in Exhibit DG-30. The Company is seeking $246.8 million for the Chesterfield environmental project (CHIA). Therefore, the environmental projects could not have been fully included in the Company's reported total.

65 *See* Company Response to Staff Set 1-26, ES Attachment Staff Set 1-26 Statement 1 Capital (JCF) R1, attached as Exhibit DG-31.

66 *See id.* Note: it is unclear if these CCR O&M costs are incremental to the O&M costs Dominion reported in Exhibit DG-28.

6. *The wet-to-dry and landfill components of the CHIA costs were imprudently incurred and should not be recovered through Rider E*

Q When did the Company begin development of the wet-to-dry component of the CHIA Project?

A The Company signed the contract in June 2015. I assume the Company was considering the decision to install the equipment during 2014 and early 2015, and possibly during earlier periods also.

Q Why did the Company assert a need to convert the units to wet to dry technology?

A In order to dispose of coal ash waste (generated from future plant operations) in a newly constructed landfill, the Company had to install wet-to-dry technology on each unit that was going to continue to operate and generate coal ash waste.

Q When did the Company begin construction of the Reymet landfill?

A The Company signed the contract for the road in May 2015, and for the landfill in January 2016.

Q Why did the Company assert a need for a new landfill?

A As discussed in Section 3, the Company states that it needed to build a new landfill in order to meet CCR and ELG regulations in order to continue to operate the Chesterfield coal units beyond the point in time in which the Company could continue to use the existing coal ash ponds. Additionally, the existing landfill was projected to be full by 2019.[67]

67 *See* Direct Testimony of Cathy Taylor at 4 and at 10. *See* Exhibit DG-10, Attachment AG Set 2-10(b) (BMH).

Q Is the existing capacity associated with the upper and lower ash ponds still projected to be full by 2019?

A No. The statement that a new landfill would be needed in 2019 was made in 2009 when the units were operating at very high capacity factors. The Company determined in August 2016 that the upper ash pond had the equivalent of 7.67 years of capacity remining, based on then current coal ash production (and therefore power generation) levels.[68] This means that the pond could continue to receive coal ash through 2023, or even beyond if generation levels drop below 2016 levels.

Q Did Dominion consider using the existing coal ash pond until it was full instead of building a new landfill?

A The Company states that it was not an option to seek an extension for the closure of the existing ash ponds.[69] However it is my understanding that the Company would be allowed to continue to operate the existing ponds through October 2020.[70]

Q What was the economic status of Chesterfield Coal Units between 2013 and 2015?

A **[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

68 *See* Exhibit DG-9, Company Response to OAG 7-99.

69 *See* Company Responses to OAG 6-80 and OAG 6-81, attached as Exhibit DG-32.

70 *See* Exhibit DG-9, Company Response to OAG 7-99. *See also* 40 CFR § 257.101 - Closure or retrofit of CCR units.

[redacted]

[END CONFIDENTIAL]

Q **What should Dominion have known about the economics of Units 3 and 4 in June of 2015?**

My retirement analysis from Section 5 shows that retirement of Unit 3 and 4 was projected to have a higher net revenue relative to the market than continued operation with the environmental project costs. Reasonable projections of operational realities would have revealed to the Company in advance of June 2015 that these units were not going to remain economic beyond 2018.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL] It is very disconcerting that the Company did not exhaustively assess the near-to-medium-term findings in its resource planning results prior to the June 2015 contract date to determine if any of the $246.8 million in planned capital expenditures could be avoided.

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71 *See* Exhibit DG-3, Attachment AG Set 4-58-3 (TF) CONF.

Q What should the Company have known about the economics of Units 5 and 6 in June of 2015?

A As with Units 3 and 4, my retirement analysis from Section 5 shows that retirement of all units was projected to have a higher net revenue relative to the market than continued operation with the environmental project costs. Reasonable projections of operational realities would have revealed to the Company in advance of June 2015 that these units might not remain economic beyond 2018.

Further, the Company should have known that, given the high level of regulatory and market uncertainty, there was significant value in deferring the wet-to-dry conversion. A reasonable decision to defer installation of the wet-to-dry technology on Units 5 and 6 should have led to a further decision to retire the units, given the market information revealed during the 2016-2018 period. The Company likely had until October 2020 to comply, not November 2018 as the Company initially stated. This means that Dominion could have deferred the decision around the CHIA project for at least two years.

Q Has Dominion conducted any analysis since 2015 to evaluate the environmental investments in light of the changing regulatory environment, falling natural gas prices, and lower than projected PJM power and capacity market prices and system demand?

A Yes. [BEGIN CONFIDENTIAL] [redacted][73]

72 *See* Company Response to OAG Set 4-58, Attachment AG Set 4-58-3 (TF) CONF, attached as Exhibit DG-3.

73 *See id.*

[redacted][75]

[END CONFIDENTIAL]

Q What is the economic status of Chesterfield Units 3—6 going forward?

A Dominion announced in March 2019 that Chesterfield Units 3 and 4 would retire by the end of March, 2019.

[BEGIN CONFIDENTIAL] [redacted]

74 *See id.*

75 *See* Exhibit DG-3, Attachment AG Set 4-58-3 (TF) CONF.

[redacted][77] [END CONFIDENTIAL]

Q What are the implications of the Company's decision to construct a new landfill as Units 3 and 4 were actively uneconomic, and Units 5 and 6 faced significant future economic uncertainty?

A The Commission should disallow recovery of the wet-to-dry component of the capital costs spent to keep Chesterfield Units 3—6 operational.[78]

The Company failed to act on clear information on Units 3 and 4 that the plants were currently uneconomic, and were going to continue to operate uneconomically.

Further, the Company should have deferred, not accelerated, decisions on installing such technology on Units 5 and 6, when faced with uncertainty of whether or not operation of Unit 5 and 6 would be economic over the near and long-terms. The Company had sufficient time to defer such decision given the CCR and ELG timelines described earlier.

The Commission should also disallow recovery of the landfill component of the capital costs spent to keep Chesterfield Units 3-6 operational. The decision to construct the landfill was predicated on a need to handle coal ash associated with continuing the (uneconomic) operation of the Chesterfield coal units. The scale at which the landfill itself was ultimately constructed was unnecessary, since

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76 *See* Company Response to OAG Set-6-88, ES Attachment AG Set 6-88-2 (TF), attached as Exhibit DG-34. *See also* Company Response to Sierra Club Set 3-3, Extraordinarily Sensitive Attachment Sierra Club Set 3-3(b) (TF), attached as Exhibit DG-35.

77 *See* Company Response to Sierra Club Set 3-3 (c), attached as Exhibit DG-36.

78 *See* Exhibit DG-3, Attachment AG Set 4-58-3 (TF) CONF.

coal ash from existing operations could have been handled in the existing ash pond structures through the likely compliance deadline of October 2020.[79]

As stated above, the Company could have deferred the decision to invest $189 million in environmental projects at least two years, until 2017. At this later date (2017) the Company would have seen falling natural gas prices, falling renewable prices, lower than projected PJM market energy and capacity prices, and lower native demand than projected driving down the economics of continued coal plant operation. In this environment, an economic evaluation of retirement compared to investment in $189 million in environmental capital costs would have indicated to the Company that retirement is the economic choice.

Q Does this conclude your direct testimony?

A Yes, it does.

79 *See* Company Response to OAG 7-99, attached as Exhibit DG-9.

Exhibit No.	Contains Confidential or Extraordinarily Sensitive Information?	Contents
DG-1	No	Resume of Devi Glick
DG-2	Extraordinarily Sensitive	Company Response to OAG 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11(b) (JJB) – Revised
DG-3	Confidential – only the attachments	Company Response to OAG Set 4-58, Attachment AG Set 4-58-3 (TF) CONF
DG-4	No	Company Response to Staff Set 12-57, Attachment Staff Set 12-57_BHM
DG-5	No	Company Response to OAG Set 4-55
DG-6	No	Company Response to OAG 4-57
DG-7	No	Company response to OAG 3-43
DG-8	No	Company Response to OAG 4-60
DG-9	No	Company Response to OAG 7-99
DG-10	No	Company Response to OAG Set 2-10, Attachment AG Set 2-10(b) (BMH)
DG-11	Extraordinarily Sensitive	Company Response to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (a) (JJB) -Revised
DG-12	Extraordinarily Sensitive	Company Response to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (c) (JJB) – Revised
DG-13	Extraordinarily Sensitive	Company Response to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (d) (JJB) – Revised
DG-14	Extraordinarily Sensitive	Company Response to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG Set 2-11 (e) (JJB) – Revised
DG-15	Extraordinarily Sensitive	Company Response to OAG Set 2-11, Confidential and Extraordinarily Sensitive Attachment AG 2-11 (f) (JJB) – Revised
DG-16	No	Company Response to OAG 5-69
DG-17	No	Company Response to OAG 6-90
DG-18	No	Company Response to OAG 2-18
DG-19	Confidential	Company Response to OAG 4-58, Attachment AG

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		Set 4-58-1 (TF) CONF
DG-20	No	Company Responses to OAG Set 2-15, OAG 2-16, OAG 2-17
DG-21	Extraordinarily Sensitive	Company Response to OAG Set 7-95, Attachment AG Set 7-95 (TF) ES
DG-22	No	Company Response to OAG 6-84, Attachment AG Set 6-84-2 (TF)
DG-23	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (k)
DG-24	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (l)
DG-25	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (m)
DG-26	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (n)
DG-27	Confidential	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (o)
DG-28	Extraordinarily Sensitive	Company Supplement Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (h-i) (JF) ES
DG-29	Confidential	Company Response to Staff Set 8-46, Confidential Attachment Staff Set 8-46 b (JLM)
DG-30	Extraordinarily Sensitive	Company Supplemental Response to Sierra Club Set 2-5, Confidential Attachment Sierra Club 2-05 (j) (JF) (ES)
DG-31	Extraordinarily Sensitive	Company Response to Staff Set 1-26, ES Attachment Staff Set 1-26 Statement 1 Capital (JCF) R1
DG-32	No	Company Response to OAG 6-80 and OAG 6-81
DG-33	Extraordinarily Sensitive	Company Response to OAG Set 2-19, Attachment AG Set 2-19 (TF) ES
DG-34	Extraordinarily Sensitive	Company Response to OAG Set 6-88, ES Attachment AG 6-88(2)(TF)
DG-35	Extraordinarily Sensitive	Company Response to Sierra Club Set 3-3, ES

		Attachment Sierra Club Set 3-3(b) (TF)
DG-36	Extraordinarily Sensitive	Company Response to Sierra Club Set 3-3(c)
DG-37	Confidential	Company Response to Sierra Club 2-02(j) (KWD) CONF

Exhibit No. DG-1

Resume of Devi Glick

Devi Glick, Senior Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, April 2019 – Present, *Associate*, January 2018 – March 2019

Conducts research and provides consulting on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower cost and lower emission resource portfolio options.
- Assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents in Kentucky, South Africa, New Mexico, Florida, South Carolina, and North Carolina.
- Contributing to the evaluation of the economics of utility plant operation and capacity planning decisions relative to market prices and alternative resource costs.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing, assessing, and co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.
- Developing a manual and providing quality control for a tool to analyze the impacts of climate measures and energy policies in Morocco.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy and identified over a billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO_2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement, and was submitted as an official federal comment, and led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales, and helped them identify alternative business models that would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

Prepared lesson plans, taught classes, graded papers and other coursework, met regularly with students.

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012

Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project.* Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station.* Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions.* Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act.* Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059.* Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule.* Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EPA*. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated April 2019

Exhibit No. DG-3

Company Response to OAG Set 4-58, Attachment AG Set 4-58-3 (TF) CONF

1904300012

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Fourth Set

The following response to Question No. 58 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 13, 2019 has been prepared under my supervision.

Ted Fasca

Ted Fasca
Manager, Generation System Planning
Virginia Electric and Power Company

Question No. 58

Reference the responses to AG 2-15, AG 2-16, and AG 2-17, provide the analyses which support the claim that at the time the decisions were made to implement the Chesterfield, Mount Storm and Clover environmental projects the coal units were economically serving the Company's native load, including the underlying commodity price assumptions and assumptions regarding costs of the environmental compliance projects that were included in the analysis.

Response:

Please see Confidential Attachment AG Set 4-58-1 (TF), Confidential Attachment AG Set 4-58-2 (TF), and Confidential Attachment AG Set 4-58-3 (TF) for information responsive to this request.

Confidential Attachment AG Set 4-58-1 (TF) provides an analysis supporting the environmental compliance projects that was conducted in 2011 when the MATS and Clean Water Act 316 b rules were proposed. At the time, the units that were identified as being potentially impacted by these pending environmental regulations were Chesapeake Energy Center units 1-4, Yorktown units 1-3, Chesterfield unit 3, Mecklenburg units 1-2, Bremo units 3-4, and Possum Point unit 5. The analysis at the time indicated that it would be more economical to retire Chesapeake units 1-4 and Yorktown units 1-2 rather than move forward with retrofitting additional environmental equipment. The analysis indicated that it would be more economical to retrofit or repower the remaining units based on the commodity forecast in 2011. Please see Confidential Attachment AG Set 4-58-2 (TF) for an analysis of the economics impacting Chesterfield unit 3, which also took place in 2011.

Chesterfield units 4-6, as well as the Mount Storm and Clover coal units, were determined not to be at risk based on actual and projected capacity factors at the time the decisions were made to implement those projects. At the time of this analysis, these units were serving the Company's native load, as evidenced by their historical capacity factors ranging from 51% to 88%, and were forecasted to continue to operate in the same range well into the future. Please see Appendix 3D of the 2011 IRP for additional details on capacity factors and Section 4.4 of the 2011 IRP for commodity price assumptions.

In addition, please see Confidential Attachment AG Set 4-58-3 (TF) for a life extension analysis that was performed in 2015 for Chesterfield, Mount Storm, and Clover that indicated continued near term operation for each of these units was still economical at that time.

Confidential Attachment AG Set 4-58-1 (TF), Confidential Attachment AG Set 4-58-2 (TF), and Confidential Attachment AG Set 4-58-3 (TF) are confidential in full and are being provided pursuant to the protections set forth in 5 VAC 5-20-170 and the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information entered on January 11, 2019.

Exhibit No. DG-4

Company Response to Staff Set 12-57, Attachment
Staff Set 12-57_BHM

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Virginia Electric and Power Company
Case No. PUR-2018-00195
Virginia State Corporation Commission Staff
Twelfth Set

The following response to Question No. 57 of the Twelfth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on March 28, 2019 has been prepared under my supervision.

Bradley M. Hanks
Manager – Construction Services
Dominion Energy Services, Inc.

Question No. 57

Please provide a table that includes the following data: (i) each project that cost recovery is being requested for within this proceeding; (ii) the specific law and/or regulation that requires the project; (iii) the date the applicable law and/or regulation was proposed; (iv) the date the applicable law and/or regulation was approved; (v) the date by which compliance was required under the approved law or regulation; (vi) the month and year the decision was made to complete the project; and (vii) the month and year the project was completed, or is expected to be completed.

Response:

See Attachment Staff Set 12-57 (BMH).

190430012

Attachment Staff Set 12-57_BMH

Project	Station	Environmental Law	Proposed Rule	Final Rule	Compliance Date[1]	Contract Date	Project Completion
Landfill	Chesterfield	CCR/ ELG	June 2010/June 2013	April 2015/ November 2015	November 2018	January 2016	September 2017
Wet to Dry Conversion	Chesterfield	CCR/ELG	June 2010/June 2013	April 2015/ November 2015	November 2018	June 2015	December 2017
Low Volume Waste Water Treatment	Chesterfield	CCR/ELG	June 2010/June 2013	April 2015/ November 2015	November 2018	August 2016	October 2017
New Flue Gas Desulfurization - South Sludge Pond	Clover	CCR	June 2010	April 2015	May 2021	October 2016	Q3 2019
New Flue Gas Desulfurization - North Sludge Pond	Clover	CCR	June 2010	April 2015	May 2021	October 2016	May 2018
Flue Gas Desulfurization - Sludge Ponds Closure	Clover	CCR	June 2010	April 2015	May 2021	October 2016	November 2018
New Pyrite Pond	Mt. Storm	CCR	June 2010	April 2015	April 2019	June 2016	November 2016
New Low Volume Waste Water Pond A	Mt. Storm	CCR	June 2010	April 2015	April 2019	June 2016	Q2 2019
New Low Volume Waste Water Pond B	Mt. Storm	CCR	June 2010	April 2015	April 2019	June 2016	December 2017
Filtration System	Mt. Storm	CCR	June 2010	April 2015	April 2019	June 2016	December 2017
Pyrite Pond Closure	Mt. Storm	CCR	June 2010	April 2015	April 2019	June 2016	August 2016
Low Volume Waste Water Pond AB Closure	Mt. Storm	CCR	June 2010	April 2015	April 2019	June 2016	July 2018/July 2017
Low Volume Waste Water Pond CD Closure	Mt. Storm	CCR	June 2010	April 2015	April 2019	June 2016	July 2017/Oct 2018

CCR -Coal Combustion Residuals Rule

ELG- Effluent Limit Guidelines

[1]Clover Power Station and Mt. Storm Power Station compliance dates are driven by the date that no additional CCR material could be placed in the pond.

Exhibit No. DG-5

Company Response to OAG Set 4-55

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Fourth Set

The following response to Question No. 55 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 13, 2019 has been prepared under my supervision.

Cathy C. Taylor
Senior Environmental and Sustainability Advisor
Virginia Electric and Power Company

Question No. 55

Provide the status of the CCR rule and other relevant environmental regulations that triggered the Chesterfield environmental projects discussed in witness Mitchell's direct testimony, immediately before the decision to implement the projects, including the expected dates of final rule implementation and the compliance deadlines that triggered each of the Chesterfield environmental projects.

Response:

EPA published its proposed CCR Rule in the Federal Register on June 21, 2010 (75 FR 35,128). The final rule was signed on December 19, 2014 and published in the Federal Register on April 17, 2015 (80 FR 20,301). Compliance deadlines in the rule were staggered from the publication date through October 2018. Virginia DEQ incorporated the CCR Rule in January 2016 (9 VAC 20-81-800). After completing a study of the category in 2009, EPA published its proposed Steam Electric Effluent Limitations Guidelines ("ELG") rule on June 7, 2013 (78 FR 34431). The final rule was signed on September 30, 2015 and published in the Federal Register on November 3, 2015 (80 FR 67837). Compliance deadlines were left to the states to implement in applicable permits as soon as possible beginning November 1, 2018 and no later than December 31, 2023. On September 23, 2016, the Virginia Department of Environmental Quality issued a renewal of Chesterfield Power Station's Virginia Pollutant Discharge Elimination System ("VPDES") permit, which set a compliance date of November 1, 2018 for ceasing discharge of CCR wastewater directly from the Upper and Lower Ash Ponds.

Exhibit No. DG-6

Company Response to OAG 4-57

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Fourth Set

The following response to Question No. 57 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 13, 2019 has been prepared under my supervision.

David J. DePippo
Senior Counsel
Dominion Energy Services, Inc.

Joshua J. Bennett
Vice President Technical Services
Dominion Energy Services, Inc.

Question No. 57

Reference the response to AG 2-11, explain why the Company decided to accelerate the dates of implementation of the environmental compliance investments and provide any impact on project costs arising from this decision.

Response:

The Company objects to this request to the extent that it would require the Company to perform original work. Subject to, and notwithstanding this objection, the Company provides the following response:

The references to an accelerated timeline set forth in the attachments to the Company's response to AG Set 2-11 relate to adjusting the planned schedule for the Environmental Projects based on the need to meet environmental compliance deadlines associated with the CCR regulations and coordination with the planned station outage in Fall 2017, as understood at the point in time that such presentations were prepared.

Exhibit No. DG-7

Company response to OAG 3-43

<u>Virginia Electric and Power Company</u>
<u>Case No. PUR-2018-00195</u>
<u>Office of the Attorney General</u>
<u>Third Set</u>

The following response to Question No. 43 of the Third Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on February 28, 2019 has been prepared under my supervision.

Joshua J. Bennett
Vice President Technical Services
Dominion Energy Services, Inc.

Question No. 43

Reference the response to AG 2-11. Provide the documentation and date of each project approval as originally requested.

Response:

Permitting work and initial engineering studies were performed for the Chesterfield Fossil Fuel Combustion Products (FFCP) Management Facility prior to the 2015 time frame. Specifically, the property for this facility was purchased in 2010, and the permit application was submitted the same year. However, the final decision to proceed with the Chesterfield Integrated Ash Product, which included the FFCP Management Facility, the Wet-To-Dry Ash Conversion Project, and the Low Volume Waste Water Treatment System ("LVWWTS") occurred in 2015. As a result, the primary major contracts were executed as indicated below:

- AMEC Wet-To-Dry Construction Agreement: June 19, 2015
- RECON Low Volume Waste Water Treatment System (LVWWTS) Construction Agreement: August 23, 2016
- RECON Fossil Fuel Combustion Products (FFCP) Facility Construction Agreement: January 19, 2016
- Wagman Haul Road Construction Agreement: May 20, 2015

Exhibit No. DG-8

Company Response to OAG 4-60

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Fourth Set

The following response to Question No. 60 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 13, 2019 has been prepared under my supervision.

Cathy C. Taylor

Cathy C. Taylor
Senior Environmental and Sustainability Advisor
Virginia Electric and Power Company

Question No. 60

Reference page 5 of Company witness Taylor's direct testimony, which of the three triggering conditions required closure of CCR ponds at the Chesterfield plant.

Response:

For the Lower and Upper Ash Ponds, either or both an exceedance of groundwater protection standards and failure to meet location restrictions for placement of CCR above the uppermost aquifer triggered a six-month deadline for commencing closure on or about October 2018 (depending on exact timing of sampling, analysis, and engineering assessments).

Exhibit No. DG-9

Company Response to OAG 7-99

19043000112

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Seventh Set

The following response to Question No. 99 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 28, 2019 has been prepared under my supervision.

Bradley M. Hanks
Manager – Construction Services
Dominion Energy Services, Inc.

Question No. 99

Provide the estimated remaining storage capacity in existing Chesterfield ash ponds at the time of the Company's decision in 2015 to proceed with the Chesterfield integrated ash project.

Response:

The Lower Ash Pond ("LAP") did not have a capacity life limitation, as the station maintained enough room in the LAP to allow the ash to settle before the sluice water was discharged to the thermal channel and coal combustion residuals ("CCRs") were excavated and hauled to the Upper Ash Pont ("UAP") as part of the station's maintenance operations. If the CCR/ELG regulations had not been implemented, the LAP would not have ceased operations.

On August 11, 2016, GAI Consultants, Inc. determined that the UAP had 3.07 million cubic yards of remaining capacity. At that time, the Company was utilizing 400,000 cy/year. Accordingly, there were 7.67 years of capacity remaining at the UAP (3.07 mcy/0.4 mcy=7.67). Based on this, the estimated 2015 capacity would have been 8.67 yrs. Regardless of the design capacity determination, however, the ELG regulations that were incorporated into the station VPDES permit required flyash and bottom ash sluicing to the LAP to cease by October 2020, which provides for an effective life of approximately four years from August 11, 2016 (or approximately five years from the 2015 decision to proceed).

Exhibit No. DG-10

Company Response to OAG Set 2-10, Attachment AG Set 2-10(b) (BMH)

ALTERNATE SITE ANALYSIS

CHESTERFIELD POWER STATION
FOSSIL FUEL COMBUSTION PRODUCTS MANAGEMENT FACILITY
CHESTERFIELD COUNTY, VIRGINIA

Dominion

Prepared for:

Dominion
5000 Dominion Boulevard
Glen Allen, Virginia 23060

June 19, 2009 (Rev 1)

Prepared by:

Golder Associates

Golder Associates Inc.
3719 Saunders Avenue
Richmond, Virginia 23227

Project #: 073-660709

TABLE OF CONTENTS

List of Appendices

1.0 EXECUTIVE SUMMARY

On behalf of Dominion Resource Services, Inc. (Dominion), Golder Associates Inc. (Golder) has prepared this siting analysis to identify and evaluate potential sites for the proposed Fossil Fuel Combustion Products (FFCP) Management Facility (Facility) for the Chesterfield Power Station (Station). As part of this analysis, the conclusions of two previous siting studies were re-evaluated. The study applied a series of state and local regulatory criteria, local land use planning criteria and a set of project-specific criteria to evaluate potential properties for an FFCP Facility.

The analysis initially identified nine potential properties within the County for evaluation. However, six of the properties were determined to be unsuitable for further consideration. Three of the potential properties were determined to be physically suitable for development of an FFCP Facility and were evaluated further. However, two of the sites are a significant distance away from the Station, which would require hauling the FFCPs on public roads. Due to transportation costs, these two sites are not economically feasible for development. The third property is a portion of the Station Property to the northwest of the power block, and this property is economical for development. The lifetime cost of hauling FFCP material is the single largest cost associated with developing an off-site private Facility. Both off-site properties are located more than nine (9) miles from the Station's FFCP loading point, adding over 100 million dollars to the total lifetime cost. Shoosmith Landfill in Chesterfield, the closest commercial landfill, was also considered as an alternative to developing a private Facility. In addition to the prohibitively high transportation and disposal costs, the Shoosmith Landfill does not have sufficient capacity.

Golder recommends development of the Station Property as the proposed FFCP Facility. The proposed on-site location is 1.25 miles from the FFCP loading area. FFCPs will be hauled from the loading area to the FFCP Facility in large dump trucks on a private road owned by Dominion. Hauling and storing the material on site will avoid approximately 32,500 dump truck round trips per year on public roads. The physical site studies conducted to date indicate the site is suitable for FFCP Facility development, with adequate soil types and volumes, adequate depth to groundwater, and absence of wetlands and streams in the proposed Facility footprint. The Station Property is also the most economical long-term location for the Facility to support the ongoing power generating operations at the Chesterfield Power Station.

1.1 PROPOSED FACILITY DESCRIPTION

Dominion intends to develop a Facility for the management and disposal of the FFCP generated from the production of electricity by Dominion stations. FFCP are defined in the Virginia Solid Waste Management Regulations (VSWMR) (9VAC20-80-10) and the Virginia Coal Combustion Byproduct Regulations (9VAC20-85-20) as:

> " coal combustion byproducts as defined in this regulation, coal combustion byproducts generated at facilities with fluidized bed combustion technology, petroleum coke combustion byproducts, byproducts from the combustion of oil, byproducts from the combustion of natural gas, and byproducts from the combustion of mixtures of coal and "other fuels" (i.e., co-burning of coal with "other fuels" where coal is at least 50% of the total fuel). For purposes of this definition, "other fuels" means waste-derived fuel product, auto shredder fluff, wood wastes, coal mill rejects, peat, tall oil, tire-derived fuel, deionizer resins, and used oil."

The current FFCP storage facility at the Chesterfield Power Station is anticipated to reach its design capacity in approximately 2019. At that time, a new storage Facility will be needed to support continued power generation at the Chesterfield Power Station.

1.2 PROPOSED FACILITY DESIGN

The Facility will be designed as an industrial landfill, in accordance with the siting and design requirements in the VSWMR. The base liner for each Phase of the Facility will be constructed as follows:

- Excavation of existing soils to design grades;
- Installation of a 60-mil High Density Polyethylene (HDPE) geomembrane liner;
- Installation of a geocomposite (GC) drainage material;
- Installation of 4-inch and 6-inch perforated HDPE leachate collection pipes; and,
- Installation of 18 inches of drainage layer material.

The base grades of the Facility will be constructed to promote leachate drainage to a sump located within each Phase where leachate will be collected and pumped out to a leachate collection system. During operation, the operations contractor will place and compact the FFCP in accordance with the specifications outlined in the Facility's permit. Once the FFCP reaches design grades, a 12-inch layer of cover soil will be placed and seeded to form the Intermediate Cover layer to protect the underlying FFCP from erosion.

The base liner and final cover systems will be constructed by experienced contractors, and overseen by qualified engineers who monitor and test each component as it is built. As areas within the Facility reach fill capacity, these areas will be covered with the final cover system. The final cover system consists of a Low Density Polyethylene (LDPE) geomembrane liner covered with 24 inches of soil to support a vegetative protective cover. When the final cover system is in place, the site will resemble a natural grassy hill. Stormwater controls are incorporated into the final cover system to prevent loss of the soil cover and maintain water quality.

FFCP will be loaded on to trucks at the loading area in preparation for hauling to the Facility. Prior to leaving the FFCP loading area, the trucks will be covered and have their wheels washed to prevent tracking of FFCP and to minimize dust from the hauling operations.

2.0 SITE EVALUATION CRITERIA

2.1 REGULATORY CRITERIA

The proposed Facility will be permitted as a captive industrial landfill, subject to both state and local regulatory requirements. The state requirements for industrial landfills are contained in the VSWMR, currently 9VAC20-80-270. In consideration of the anticipated adoption of Amendment 7 of the VSWMR, the siting requirements in Amendment 7 (9VAC20-81-120) were applied for this study. The siting criteria for industrial landfills in Amendment 7 are more restrictive than those in the current VSWMR, and therefore, provide for a conservative approach for this study. Chesterfield County has two levels of regulation for landfills. First, the County's siting ordinance found in Chesterfield County Code Sections 11-71 *et seq.* and 11-91 *et seq.* governs the technical requirements of siting a solid waste disposal facility in the County. Second, the County's zoning ordinance (Chesterfield County Code section 19-1 *et seq.*) limits the operation of solid waste disposal facilities to specific zoning districts and requires the issuance of a conditional use permit for operation of such facilities. Lastly, the County has developed long-range land use plans to guide development in the County. Land use for an FFCP Facility must be compatible with the County's land use plans.

2.1.1 VSWMR Criteria (Amendment 7)

Amendment 7 of the VSWMR consolidates the siting of all non-hazardous landfill types in Section 9VAC20-81-120 of the Virginia Administrative Code. The siting of all new industrial landfills will be governed by the following:

Exhibit No. DG-16

Company Response to OAG 5-69

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Fifth Set

The following response to Question No. 69 of the Fifth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 14, 2019 has been prepared under my supervision.

Bruce Petrie for T. Fasca

Ted Fasca
Manager, Generation System Planning
Virginia Electric and Power Company

Question No. 69

Did DVP evaluate the alternative of placing all four coal units at the Chesterfield Plant in cold storage for several years until there was greater certainty in CCR compliance requirements as an alternative to moving forward with the wet-to-dry conversion with landfill project in 2015 at the Chesterfield plant? If so, provide the economic analyses comparing these options. If not, explain why not.

Response:

The Company evaluated compliance with the CCR requirements for the Chesterfield Plant based on the proposed requirements and the operational status of the units. From the time these rules were proposed in 2011, and until they became effective in 2015, the Chesterfield Plant was economically serving customer load and was forecasted to do so for the foreseeable future. Retirement and cold storage were not considered given the high utilization of the Chesterfield Plant. Thus, the plan for CCR compliance was developed in order to maintain the viability of these assets to meet customer needs. See the Company's responses to AG Set 2-15, 16, 17, 19, 30 and AG Set 4-5.

Exhibit No. DG-17

Company Response to OAG 6-90

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Sixth Set

The following response to Question No. 90 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 26, 2019 has been prepared under my supervision.

Bradley M. Hanks
Manager – Construction Services
Dominion Energy Services, Inc.

Question No. 90

Provide the estimated portion of the Chesterfield integrated ash project costs that could have been avoided if the decision to retire these units had been made before the ash project engineering and construction contracts were executed.

Response:

See the Company's response to AG Set 6-89. Additionally, the Company states that no project costs were viewed as avoidable, as Chesterfield Units 3 and 4 were both economically a net positive to the ratepayer at the time the decision to tie in to the Wet-to-Dry system was made.

Exhibit No. DG-18

Company Response to OAG 2-18

19043 0012

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Second Set

The following response to Question No. 18 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on February 1, 2019 has been prepared under my supervision.

S. for

Ted Fasca
Manager - Generation System Planning
Virginia Electric and Power Company

Question No. 18

Were the environmental investments proposed for Chesterfield, Mount Storm, and Clover coal units that the Company is seeking to recover through Rider E evaluated in conjunction with the Company's annual IRP process? If so, provide the results of these IRP analyses including all underlying cost assumptions. If not, explain why not.

Response:

The Company's IRP takes into account existing and future environmental regulations when developing a cost-effective, reliable resource plan. The uncertainty regarding the precise timing and impact of these rules present a challenge because, during any given IRP, many rules are not in their final form. Nevertheless, the Company makes a reasonable attempt to evaluate and predict the financial and other impacts of such rules.

In the Company's 2011 Plan, the Company accounted for a number of significant, newly proposed US EPA regulations that were expected to affect certain units across the Company's fleet of generation resources. To address these newly proposed rules in the 2011 IRP, the Company followed a multi-step assessment that was described in Company Witness Glenn Kelly's 2011 IRP Rebuttal Testimony and Rebuttal Schedule 1. See Attachment AG Set 2-18 (TF). IRPs subsequent to the 2011 IRP have continued to assess and evaluate the financial and other impacts of such rules, including after those rules were finalized.

Exhibit No. DG-20

Company Responses to OAG Set 2-15, OAG 2-16, OAG 2-17

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Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Second Set

The following response to Question No. 15 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on February 1, 2019 has been prepared under my supervision.

S. for

Joshua J. Bennett
Vice President Technical Services
Dominion Energy Services, Inc.

S. for

Bradley M. Hanks
Manager Construction Services
Dominion Energy Services, Inc.

S. for

Ted Fasca
Manager - Generation System Planning
Virginia Electric and Power Company

Question No. 15

Was cold storage considered as an alternative to the environmental investments proposed for Chesterfield, Mount Storm, and Clover coal units that the Company is seeking to recover through Rider E? If so, provide the results of these alternative analyses and explain why cold storage was not selected as the preferred option. If not, explain why not.

Response:

Cold storage was not considered as an alternative to the Environmental Projects because at the time the decisions were made to implement those projects in order to ensure compliance with environmental law and regulations, the coal units at the Power Stations economically were serving the Company's native load. See the Company's responses to AG Set 2-18 and 2-19.

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Second Set

The following response to Question No. 16 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on February 1, 2019 has been prepared under my supervision.

Joshua J. Bennett
Vice President Technical Services
Dominion Energy Services, Inc.

Bradley M. Hanks
Manager Construction Services
Dominion Energy Services, Inc.

Ted Fasca
Manager - Generation System Planning
Virginia Electric and Power Company

Question No. 16

Was early retirement considered as an alternative to the environmental investments proposed for Chesterfield, Mount Storm, and Clover coal units that the Company is seeking to recover through Rider E? If so, provide the results of these alternative analyses and explain why early retirement was not selected as the preferred option. If not, explain why not.

Response:

Early retirement was not considered as an alternative to the Environmental Projects because at the time the decisions were made to implement those projects in order to ensure compliance with environmental law and regulations, the coal units at the Power Stations economically were serving the Company's native load. See the Company's responses to AG Set 2-18 and 2-19.

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Second Set

The following response to Question No. 17 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on February 1, 2019 has been prepared under my supervision.

S. for

Joshua J. Bennett
Vice President Technical Services
Dominion Energy Services, Inc.

S. for

Bradley M. Hanks
Manager Construction Services
Dominion Energy Services, Inc.

S for

Ted Fasca
Manager - Generation System Planning
Virginia Electric and Power Company

Question No. 17

Was conversion of the existing coal units to burn natural gas considered as an alternative to the environmental investments proposed for Chesterfield, Mount Storm, and Clover coal units that the Company is seeking to recover through Rider E? If so, provide the results of these alternative analyses and explain why gas conversion was not selected as the preferred option. If not, explain why not.

Response:

Conversion of the existing coal units to burn natural gas was not considered as an alternative to the Environmental Projects because at the time the decisions were made to implement those projects in order to ensure compliance with environmental law and regulations, the coal units at the Power Stations economically were serving the Company's native load. See the Company's responses to AG Set 2-18 and 19.

Exhibit No. DG-22

Company Response to OAG 6-84, Attachment
AG Set 6-84-2 (TF)

19043012

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Sixth Set

The following response to Question No. 84 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 26, 2019 has been prepared under my supervision.

Ted Fasca

Ted Fasca
Manager, Generation System Planning
Virginia Electric and Power Company

Question No. 84

Reference Figure 3.1.3.1 on page 33 of DVP's 2015 IRP, for each of the identified environmental regulations, indicate whether the regulation was expected to impact costs of the Clover, Mount Storm or Chesterfield coal units, and if so, provide estimated compliance costs for each regulation reflected in the IRP analysis for each unit. If any expected compliance costs were not included in the IRP analysis, explain why not.

Response:

See Attachment AG Set 6-84-1 (TF) for the Environmental Impact Study spreadsheet that provides the high level environmental plan for affected units. See Attachment AG Set 6-84-2 (TF) for the costs associated with the Clover, Mt. Storm and Chesterfield coal units that were reflected in the 2015 IRP analysis.

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Chesterfield Power Station
Balance of Life Cost Data for 2015 IRP
($ in Thousands)

Escalation factor 1.96%

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Planned Generation - Sept 2014 Promod (0902 BASE)													
U3	MWh	144,627	88,962	203,014	226,708	211,374	206,202	196,109	192,145	157,310	-	-	-
U4	MWh	544,862	544,235	655,269	673,057	712,675	696,026	681,009	639,933	591,978	-	-	-
U5	MWh	1,541,856	1,445,892	1,699,139	1,895,602	1,660,289	1,876,488	1,758,904	1,728,545	1,432,127	-	-	-
U6	MWh	3,671,738	3,626,267	3,835,716	4,556,802	4,349,349	4,307,082	4,170,620	4,025,497	3,720,045	-	-	-
U7	MWh	1,610,251	1,431,696	1,203,965	1,053,562	1,115,936	1,045,859	1,026,522	952,455	967,929	-	-	-
U8	MWh	1,558,955	1,630,729	1,200,580	1,316,954	1,076,232	1,189,735	1,230,962	1,142,552	1,048,948	-	-	-
Total	MWh	9,072,290	8,767,781	8,797,682	9,722,685	9,125,855	9,321,392	9,064,125	8,681,128	7,918,336	-	-	-
Total Station Headcount		255	255	255	255	255	255	255	255	255	255	255	255
Total Station O&M													
Total	Labor	31,510	31,090	31,299	32,205	33,159	34,113	34,782	35,463	36,158	36,867	37,590	38,327
Total	Enviro Equip. VOM (ash, ammonia, urea, etc.)	11,970	11,713	12,801	14,625	14,122	14,603	14,889	15,181	15,479	15,782	16,091	16,407
Total	Materials	5,722	6,207	6,411	6,559	6,449	6,541	6,669	6,799	6,933	7,069	7,207	7,348
Total	Services	8,888	9,397	10,139	9,349	9,850	10,040	10,237	10,438	10,642	10,851	11,064	11,280
Total	Miscellaneous	1,064	1,226	1,321	1,518	1,374	1,383	1,410	1,438	1,466	1,495	1,524	1,554
Total	Planned Outage	4,840	20,936	20,603	16,212	18,633	27,859	18,537	18,900	19,271	19,648	20,033	20,426
Total	Total Station O&M	63,994	80,569	82,574	80,468	83,587	94,539	86,524	88,220	89,949	91,712	93,510	95,342
Headcount Allocators													
U3		1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
U4		6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
U5		15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
U6		62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%
U7		8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
U8		8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Enviro. Equip. VOM Allocators													
U3		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
U4		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
U5		39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
U6		39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%	39%
U7		7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
U8		7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Routine O&M Allocators (Materials, Services, Misc.)													
U3		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
U4		9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
U5		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
U6		46%	46%	46%	46%	46%	46%	46%	46%	46%	46%	46%	46%
U7		11%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%
U8		11%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Capital - Unit Common Allocators													
U3		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
U4		10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
U5		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
U6		45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
U7		10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
U8		10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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Chesterfield Power Station
Balance of Life Cost Data for 2015 IRP
($ in Thousands)

Escalation factor 1.96%

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
U3 Total O&M													
U3	Labor	315	311	313	322	332	341	348	355	362	369	376	383
U3	Enviro Equip. VOM (ash, ammonia, urea, etc.)	542	530	579	662	639	661	674	687	700	714	728	742
U3	Materials	257	279	288	295	290	294	300	306	312	318	324	331
U3	Services	400	423	456	421	443	452	461	470	479	488	498	508
U3	Miscellaneous	48	55	59	68	62	62	63	65	66	67	69	70
U3	Planned Outage	1,150	-	1,470	-	1,770	-	746	761	776	791	806	822
Total U3	Total O&M	2,712	1,598	3,166	1,768	3,536	1,810	2,592	2,643	2,694	2,747	2,801	2,856
U4 Total O&M													
U4	Labor	1,891	1,865	1,878	1,932	1,990	2,047	2,087	2,128	2,170	2,212	2,255	2,300
U4	Enviro Equip. VOM (ash, ammonia, urea, etc.)	542	530	579	662	639	661	674	687	700	714	728	742
U4	Materials	486	528	545	557	548	556	567	578	589	601	613	625
U4	Services	756	799	862	795	837	853	870	887	905	922	940	959
U4	Miscellaneous	90	104	112	129	117	118	120	122	125	127	130	132
U4	Planned Outage	1,640	-	2,866	1,000	1,596	-	1,207	1,231	1,255	1,279	1,304	1,330
Total U4	Total O&M	5,405	3,826	6,842	5,075	5,727	4,235	5,524	5,633	5,743	5,856	5,970	6,087
U5 Total O&M													
U5	Labor	4,726	4,664	4,695	4,831	4,974	5,117	5,217	5,320	5,424	5,530	5,638	5,749
U5	Enviro Equip. VOM (ash, ammonia, urea, etc.)	4,657	4,557	4,980	5,690	5,494	5,681	5,793	5,906	6,022	6,140	6,260	6,383
U5	Materials	1,116	1,210	1,250	1,279	1,258	1,275	1,300	1,326	1,352	1,378	1,405	1,433
U5	Services	1,733	1,832	1,977	1,823	1,921	1,958	1,996	2,035	2,075	2,116	2,157	2,200
U5	Miscellaneous	208	239	258	296	268	270	275	280	286	292	297	303
U5	Planned Outage	-	6,225	3,580	1,581	9,572	3,030	4,076	4,156	4,238	4,321	4,405	4,492
Total U5	Total O&M	12,440	18,727	16,740	15,500	23,486	17,331	18,658	19,024	19,397	19,777	20,164	20,560
U6 Total O&M													
U6	Labor	19,536	19,276	19,405	19,967	20,559	21,150	21,565	21,987	22,418	22,858	23,306	23,762
U6	Enviro Equip. VOM (ash, ammonia, urea, etc.)	4,657	4,557	4,980	5,690	5,494	5,681	5,793	5,906	6,022	6,140	6,260	6,383
U6	Materials	2,632	2,855	2,949	3,017	2,967	3,009	3,068	3,128	3,189	3,252	3,315	3,380
U6	Services	4,089	4,323	4,664	4,301	4,531	4,619	4,709	4,801	4,895	4,991	5,089	5,189
U6	Miscellaneous	489	564	608	698	632	636	649	662	674	688	701	715
U6	Planned Outage	1,585	3,615	12,687	3,000	3,560	13,829	6,504	6,632	6,762	6,894	7,029	7,167
Total U6	Total O&M	32,988	35,190	45,293	36,673	37,742	48,924	42,287	43,116	43,961	44,823	45,701	46,597
U7 Total O&M													
U7	Labor	2,521	2,487	2,504	2,576	2,653	2,729	2,783	2,837	2,893	2,949	3,007	3,066
U7	Enviro Equip. VOM (ash, ammonia, urea, etc.)	786	769	841	961	928	959	978	997	1,017	1,037	1,057	1,078
U7	Materials	615	667	689	705	693	703	717	731	745	760	775	790
U7	Services	956	1,010	1,090	1,005	1,059	1,079	1,100	1,122	1,144	1,166	1,189	1,213
U7	Miscellaneous	114	132	142	163	148	149	152	155	158	161	164	167
U7	Planned Outage	465	3,011	-	6,760	2,135	5,000	2,952	3,010	3,069	3,129	3,190	3,253
Total U7	Total O&M	5,457	8,077	5,266	12,170	7,615	10,620	8,682	8,852	9,025	9,202	9,383	9,566
U8 Total O&M													
U8	Labor	2,521	2,487	2,504	2,576	2,653	2,729	2,783	2,837	2,893	2,949	3,007	3,066
U8	Enviro Equip. VOM (ash, ammonia, urea, etc.)	786	769	841	961	928	959	978	997	1,017	1,037	1,057	1,078
U8	Materials	615	667	689	705	693	703	717	731	745	760	775	790
U8	Services	956	1,010	1,090	1,005	1,059	1,079	1,100	1,122	1,144	1,166	1,189	1,213
U8	Miscellaneous	114	132	142	163	148	149	152	155	158	161	164	167
U8	Planned Outage	-	8,085	-	3,871	-	6,000	3,051	3,111	3,172	3,234	3,298	3,362
Total U8	Total O&M	4,992	13,151	5,266	9,281	5,480	11,620	8,781	8,953	9,129	9,308	9,490	9,676

190430012

Chesterfield Power Station
Balance of Life Cost Data for 2015 IRP
($ in Thousands)

Escalation factor **1.96%**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capital												
Unit Common - Capital												
Chesterfield Blankets	-	-	-	2,428	2,500	2,500	3,014	3,073	3,133	3,195	3,257	3,321
CH UC(3,4,5) Mercury and PM Monitoring	-	-	-	-	-	-	-	-	-	-	-	-
CH0 T12 Lighting Replacement	-	-	-	-	-	-	-	-	-	-	-	-
CH0 Thaw Shed Heater Replacement	-	-	-	-	-	-	-	-	-	-	-	-
CH0 Diesel Fuel Tank Replacement	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Total Common Capital	-	-	-	2,428	2,500	2,500	3,014	3,073	3,133	3,195	3,257	3,321
U3 - Capital												
Unit Common Allocated	-	-	-	121	125	125	151	154	157	160	163	166
CH3 RSST-1C Replacement	100	1,177	-	-	-	-	-	-	-	-	-	-
CH3 Voltage Regulator Replacement	-	-	25	505	-	-	-	-	-	-	-	-
CH3 Partial Waterwalls Replacement	-	-	-	1,002	12,777	250	-	-	-	-	-	-
CH3 Generator Rotor Rewind	-	-	1,100	-	-	-	-	-	-	-	-	-
CH3 HP Rotor Replacement	6	6	1,682	7,462	-	-	-	-	-	-	-	-
CH3 Boiler Duct Work	-	-	1,000	-	-	-	-	-	-	-	-	-
CH3 Boiler Controls - BMS & Flame Scanner Repl	-	-	-	401	6,613	-	-	-	-	-	-	-
CH3 ESP Electrode/Plate Replacement	-	-	-	-	-	-	-	-	-	-	-	-
CH3 ESP TR Replacement	-	-	-	-	-	-	250	-	-	-	-	-
CH3 Burner Corners (O&M)	-	-	-	-	-	-	-	-	-	-	-	-
CH3 WW Repair (Capital)	-	2,000	-	-	-	-	-	-	-	-	-	-
Environmental Strategist - 316(b) - includes studies	58	59	186	190	548	1,113	1,731	-	-	-	-	-
Environmental Strategist - ELG (Effluent)	-	-	-	-	147	1,067	542	-	-	-	-	-
Balance of life projected capex - 6 year average	-	-	-	-	-	-	2,039	2,079	2,120	2,161	2,204	2,247
Reymet Road Wet-to-Dry Conversion	136	535	1,776	1,413	101	-	-	-	-	-	-	-
Reymet Road Water Treatment	27	128	231	157	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Total U3 Capital	327	3,905	5,999	11,251	20,311	2,556	4,713	2,233	2,277	2,321	2,367	2,413
U4 - Capital												
Unit Common Allocated	-	-	-	243	250	250	301	307	313	319	326	332
CH4 Catalyst Layer 1 Replacement	-	-	-	-	-	-	-	-	-	-	-	-
CH4 Catalyst Layer 2 Replacement	-	-	425	1,026	-	-	-	-	-	-	-	-
CH4 Catalyst Layer 3 Replacement	-	-	-	-	471	1,116	-	-	-	-	-	-
CH4 Voltage Regulator Replacement	-	-	95	506	-	-	-	-	-	-	-	-
CH4 Generator Rotor Rewind	-	-	-	900	-	-	-	-	-	-	-	-
CH4 Radiant Reheater Replacement & Waterwall	-	-	-	-	-	-	-	-	-	-	-	-
CH4 Burner Corner and Windbox Replacement (MATS)	-	-	-	-	-	-	-	-	-	-	-	-
CH4 Reheater Pendant Replacement	-	-	-	-	-	-	-	-	-	-	-	-
CH4 Turbine L-0 DFLP Blades (11,000 hrs remaining)	-	-	-	2,704	3,165	-	-	-	-	-	-	-
CH4 BMS System & Flame Scanners Replacement	-	-	-	401	6,613	-	-	-	-	-	-	-
CH4 ESP Electrode/Plate Replacement	-	-	-	-	-	-	-	-	-	3,500	-	-
CH4 ESP TR Replacement	-	-	-	-	-	-	500	-	-	-	-	-
Environmental Strategist - 316(b) - includes studies	89	91	288	293	846	1,720	2,674	-	-	-	-	-
Environmental Strategist - ELG (Effluent)	-	-	-	-	246	1,782	905	-	-	-	-	-
Balance of life projected capex - 6 year average	-	-	-	-	-	-	3,059	3,119	3,180	3,242	3,306	3,371
Reymet Road Wet-to-Dry Conversion	511	3,273	5,731	4,194	341	-	-	-	-	-	-	-
Reymet Road Water Treatment	102	783	745	467	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Total U4 Capital	702	4,147	7,283	10,734	11,932	4,868	7,439	3,426	3,493	7,062	3,631	3,703

190430012

Chesterfield Power Station
Balance of Life Cost Data for 2015 IRP
($ in Thousands)

Escalation factor 1.96%

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
U5 - Capital												
Unit Common Allocated	-	-	-	486	500	500	603	615	627	639	651	664
CH 5 Catalyst Layer 2 Replacement	-	-	-	-			-	-	-	-	-	-
CH 5 Catalyst Layer 3 Replacement	-	-	830	1,699			-	-	-	-	-	-
CH 5 Catalyst Layer 1 Replacement	-	-	-	-	912	1,856	-	-	-	-	-	-
CH5 ESP "F" and "G" Field Replacements	-	-	-	400	4,606		-	-	-	-	-	-
CH5 Air Preheater Basket Replacement	-	-	-	501	2,503	-	-	-	-	-	-	-
CH5 BMS Block I/O Replacement	-	-	-	150	802	-	-	-	-	-	-	-
CH5 Replace 5th and 6th Point Heaters	-	-	-	-	3,500	-	-	-	-	-	-	-
CH5 CW Travelling Screen Replacement	-	-	-	-			-	-	-	-	-	-
CH5 PA Ductwork Replacement	-	-	-	175	2,441		-	-	-	-	-	-
CH5 SXS-2 Transformer Replacement	-	-	-	-	1,251		-	-	-	-	-	-
Environmental Strategist - 316(b) - includes studies	168	172	542	552	1,595	3,240	5,039	-	-	-	-	-
Environmental Strategist - ELG (Effluent)	-	-	-	-	503	3,656	1,860	-	-	-	-	-
Balance of life projected capex - 6 year average	-	-	-	-	-	-	4,068	4,147	4,229	4,312	4,396	4,482
Reymet Road Wet-to-Dry Conversion	1,447	8,696	14,861	11,813	795	-						
Reymet Road Water Treatment	287	2,080	1,931	1,314	-	-	-	-	-	-	-	-
Total U5 Capital	1,903	10,948	18,164	17,090	19,403	9,253	11,569	4,762	4,855	4,951	5,048	5,146
U6 - Capital												
Unit Common Allocated	-	-	-	1,093	1,125	1,125	1,356	1,383	1,410	1,438	1,466	1,494
Environmental Strategist - 316(b) - includes studies	359	366	1,153	1,175	3,395	6,898	10,727					
Environmental Strategist - ELG (Effluent)	-	-	-	-	973	7,073	3,598					
Balance of life projected capex - 6 year average							9,738	9,929	10,123	10,322	10,524	10,730
Reymet Road Wet-to-Dry Conversion	3,445	21,809	33,548	28,397	2,082	-						
Reymet Road Water Treatment	684	5,216	4,359	3,159	-	-						
CH6 "A" & "B" RSST Replacements	-	-	-	-			-	-	-	-	-	-
CH6 Mercury and PM CEMS Replacements	-	-	-				-	-	-	-	-	-
CH6 Replace Water Walls & Coutant Bottom	-	-	-	-	-	-	-	-	-	-	-	-
CH6 Ash Pit Replacement	-	-	-	-		10,016	-	-	-	-	-	-
CH6 Gravimetric Feeder Conversion	100	428	-	-			-	-	-	-	-	-
CH6 Replace 7th Point Heaters A&B	-	-	-	-		2,750	-	-	-	-	-	-
CH6 Catalyst Layer 2 Replacement	-	-	-	-			-	-	-	-	-	-
CH6 Catalyst Layer 3 Replacement	-	-	-	-			-	-	-	-	-	-
CH6 Catalyst Layer 1 Replacement	-	-	1,562	3,217			-	-	-	-	-	-
CH6 Catalyst Layer 2 Replacement	-	-	-	-	1,719	3,510	-	-	-	-	-	-
CH6 Generator Stator Rewind	-	-	13,200	-		-	-	-	-	-	-	-
CH6 "B" Air Removal Pump Replacement	-	-	-	-			-	-	-	-	-	-
CH6 "A" Air Removal Pump Replacement	700	-	-	-			-	-	-	-	-	-
CH6 10th Row Diaphragm Replacement	-	800	772	-			-	-	-	-	-	-
CH6 ID Fan Rotor Replacements	-	-	-	-			-	-	-	-	-	-
CH6 Condenser CW Valve Replacements	-	-	-	-			-	-	-	-	-	-
CH6 IP 8th Stage TE/GE Buckets	-	500	1,001	-			-	-	-	-	-	-
CH6 IP Packing Replacement	-	250	251	-			-	-	-	-	-	-
CH6 Air Preheater Basket Replacement	-	1,000	2,503	-			-	-	-	-	-	-
CH6 Alterrex Rotor and Stator Rewind	-	100	1,902	-			-	-	-	-	-	-
CH6 "A" Baghouse Bag Replacement	-	-	-	-			-	-	-	-	-	-
CH6 "B" Baghouse Bag Replacement	-	-	-	-			-	-	-	-	-	-
CH6 CW Travelling Screen Replacement	-	-	-	-			-	-	-	-	-	-
CH6 FG and Secondary Duct EXJ Replacements	-	-	-	-	626	-	-	-	-	-	-	-
CH6 Sootblower Replacements	-	-	1,001	-			-	-	-	-	-	-
CH6 Switchyard 4 kV Oil-filled Breaker Replacements	-	-	-	-	-	-	-	-	-	-	-	-
Total U6 Capital	11,082	51,616	71,105	52,227	18,265	34,579	25,418	11,311	11,533	11,759	11,990	12,225

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Chesterfield Power Station
Balance of Life Cost Data for 2015 IRP
($ in Thousands)

Escalation factor 1.96%

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
U7 - Capital												
Unit Common Allocated	-	-	-	243	250	250	301	307	313	319	326	332
CH7 Replacement CI Liners	-	-	-	-	-	-	-	-	-	-	-	-
CH7 Spare Cranking Motor	-	-	-	-	1,750	-	-	-	-	-	-	-
CH7 HRSG RH/SH Front Module Replacements	2,400	9,750	37	-	-	-	-	-	-	-	-	-
CH7 Steam Sample Panel	-	-	-	-	-	-	-	-	-	-	-	-
CH7 Compressor Discharge Casing Replacement	-	-	250	1,577	-	-	-	-	-	-	-	-
CH7 GT Generator Rotor Rewind	-	-	100	1,701	-	-	-	-	-	-	-	-
CH7 BOP DCS Replacement	-	-	420	2,903	-	-	-	-	-	-	-	-
CH7 GT Inspection Strategy - 2014 (HGP) -No Parts Needed	-	-	-	-	-	-	-	-	-	-	-	-
CH7 GT Inspection Strategy - 2018 (Major)-Rotor Refurbishmer	-	-	-	-	-	-	-	-	-	-	-	-
CH7 FOR and AFT Expansion Joint Replacement	-	-	-	-	50	700	-	-	-	-	-	-
CH7 LP Evaporator Replacement	-	-	-	-	2,004	8,006	-	-	-	-	-	-
CH7 Mark IV Controls	-	-	-	-	-	-	-	-	-	-	-	-
Environmental Strategist - 316(b) - includes studies	123	125	396	403	1,164	2,366	3,679	-	-	-	-	-
Balance of life projected capex - 6 year average	-	-	-	-	-	-	2,039	2,079	2,120	2,161	2,204	2,247
Total U7 Capital	2,523	9,875	1,203	6,827	5,218	11,322	6,019	2,386	2,433	2,481	2,530	2,579
U8 - Capital												
Unit Common Allocated	-	-	-	243	250	250	301	307	313	319	326	332
CH8 Replacement CI Liners	-	-	-	-	-	-	-	-	-	-	-	-
CH8 Spare Cranking Motor	-	-	-	-	1,750	-	-	-	-	-	-	-
CH8 HRSG RH/SH Front Module Replacements	2,400	9,750	37	-	-	-	-	-	-	-	-	-
CH8 Steam Sample Panel	-	-	-	-	-	-	-	-	-	-	-	-
CH8 FOR and AFT Expansion Joint Replacement	-	-	750	-	-	-	-	-	-	-	-	-
CH8 GT HGP Inspection - 2016	-	-	-	-	-	-	-	-	-	-	-	-
CH8 GT Combustion Inspection -2017 - New Lids	-	-	-	1,000	-	-	-	-	-	-	-	-
CH8 GT Major Inspection - 2019 -w/Rotor Part	-	-	-	-	-	-	-	-	-	-	-	-
CH8 Compressor Discharge Casing Replacement	-	-	-	250	1,604	-	-	-	-	-	-	-
CH8 BOP DCS Replacement	-	-	-	450	3,005		-	-	-	-	-	-
CH8 Mark IV Controls	-	-	-	-	-	-	-	-	-	-	-	-
CH8 Stage 1 Bucket Replacement	-	-	-	-	-	-	-	-	-	-	-	-
CH8 LP Evaporator Replacement	-	-	-	-	2,003	8,022	-	-	-	-	-	-
CH8 GT Generator Rotor Rewind	-	-	-	-	-	2,004	-	-	-	-	-	-
Environmental Strategist - 316(b) - includes studies	123	125	396	403	1,164	2,366	3,679	-	-	-	-	-
Balance of life projected capex - 6 year average	-	-	-	-	-	-	2,039	2,079	2,120	2,161	2,204	2,247
	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Total U8 Capital	2,523	9,875	1,183	2,346	9,776	12,642	6,019	2,386	2,433	2,481	2,530	2,579
Total Capital by Unit												
U1	-	-	-	-	-	-	-	-	-	-	-	-
U2	-	-	-	-	-	-	-	-	-	-	-	-
U3	327	3,905	5,999	11,251	20,311	2,556	4,713	2,233	2,277	2,321	2,367	2,413
U4	702	4,147	7,283	10,734	11,932	4,868	7,439	3,426	3,493	7,062	3,631	3,703
U5	1,903	10,948	18,164	17,090	19,408	9,253	11,569	4,762	4,855	4,951	5,048	5,146
U6	11,082	51,616	71,105	52,227	18,265	34,579	25,418	11,311	11,533	11,759	11,990	12,225
U7	2,523	9,875	1,203	6,827	5,218	11,322	6,019	2,386	2,433	2,481	2,530	2,579
U8	2,523	9,875	1,183	2,346	9,776	12,642	6,019	2,386	2,433	2,481	2,530	2,579
Total — Total Station Capital	19,059	90,367	104,937	100,475	84,911	75,219	61,177	26,505	27,025	31,054	28,094	28,645
Total O&M and Capital by Unit												
U3	3,039	5,503	9,166	13,019	23,847	4,366	7,305	4,875	4,971	5,068	5,168	5,269
U4	6,107	7,973	14,126	15,809	17,659	9,103	12,964	9,059	9,236	12,917	9,602	9,790
U5	14,342	29,675	34,904	32,590	42,894	26,584	30,227	23,786	24,252	24,727	25,212	25,706
U6	44,070	86,806	116,398	88,900	56,007	83,503	67,705	54,427	55,494	56,582	57,691	58,822
U7	7,980	17,952	6,469	18,997	12,834	21,941	14,701	11,238	11,458	11,683	11,912	12,146
U8	7,515	23,026	6,449	11,627	15,257	24,261	14,800	11,340	11,562	11,788	12,019	12,255
Total — Total Station O&M and Capital	83,053	170,936	187,511	180,943	168,498	169,758	147,701	114,725	116,974	122,766	121,604	123,987

Book Life	
U3	2027
U4	2030
U5	2034
U6	2039
U7	2026
U8	2028

2027

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Chesterfield Power Station
Balance of Life Cost Data for 2015 IRP
($ in Thousands)

Escalation factor **1.96%**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Budget Construction												
Chesterfield Reymet Road Phase 1	5,785	21,147	9,857	15,186	8,344	3,207						
Reymet Road Wet-to-Dry Conversion	5,539	34,314	55,916	45,818	3,319	-						
Reymet Road Water Treatment	1,109	8,207	7,265	5,097	-	-						
	12,433	63,667	73,034	66,101	11,663	3,207						
Budget Environmental	920	939	2,580	3,016	10,583	31,282						

Analysis should be completed without Reymet Road Phase 1 included. If 1 or more coal units pass analysis, Reymet Rd Phase 1 would then be needec

Exhibit No. DG-32

Company Response to OAG 6-80 and OAG 6-81

1904300012

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Sixth Set

The following response to Question No. 80 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 26, 2019 has been prepared under my supervision.

Cathy C. Taylor
Senior Environmental and Sustainability Advisor
Virginia Electric and Power Company

Question No. 80

Reference the supplemental un-redacted response to AG 2-11, Attachment b, pages 4-6, was extension of the closure of the existing coal ash ponds at the Chesterfield Plant until 2023 an alternative to proceeding with the project immediately? If not, explain why not.

Response:

No, it was not an option for the Company to seek an extension for the closure until 2023. Once the obligation to close is triggered for a pond, then steps must be taken by the Company to close the pond and ash can no longer be placed in the pond. With publication of the signed CCR Rule in December 2014, the Company anticipated that closure of both ponds at the Chesterfield Power Station likely would be triggered no later than October 2018.

Virginia Electric and Power Company
Case No. PUR-2018-00195
Office of the Attorney General
Sixth Set

The following response to Question No. 81 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Office of the Attorney General received on March 26, 2019 has been prepared under my supervision.

Cathy C. Taylor
Senior Environmental and Sustainability Advisor
Virginia Electric and Power Company

Question No. 81

Reference the supplemental un-redacted response to AG 2-11, Attachment b, pages 4-6, did DVP evaluate extension of the closure of the existing coal ash ponds at the Chesterfield Plant until 2023 as an alternative to proceeding with the project in 2015? If not, explain why not. If so, provide the evaluation and results.

Response:

No, it was not an option for the Company to seek an extension for the closure until 2023. See the Company's response to AG Set 6-80.